THE OIL AND GAS INVESTMENT CLIMATE: CHANGES OVER A DECADE

DataMetrics Limited

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Preface

This study was undertaken under contract for the Canadian Energy Research Institute. Most of the work was carried out over the period August to November 1983.

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Work undertaken by Michael Brennan of the University of British Columbia on capital markets and Alexander Kemp of the University of Aberdeen on North Sea and United States reservoir investment is acknowledged in the study. Their contributions are not intended to implicate them in our overall conclusions.

G. C. Watkins,
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OVERVIEW

A comparison between 1972 and 1982 has been made of four key determinants of investment in the Canadian oil and gas petroleum production sector: expected returns, achieved returns, capital market behaviour and industry perceptions.

In terms of expected real rates of return on individual oil and gas reservoirs, between 1972 and 1982 the general incentive to invest in the production of new gas supplies in Alberta has deteriorated while that for oil has improved somewhat; for North Sea oil it is much the same while for North Sea gas it has improved, and in Texas oil investment has become much more attractive as long as exploration efforts finally yield success.

In terms of achieved real returns, the Canadian oil and gas production sector enjoyed some substantial increases in profitability in the 1970s, superceded by lower levels in the 1980s. When these returns are adjusted for increasing replacement costs, they fall substantially.

In terms of capital markets, real equity rates of return required by investors in the oil and gas production sector increased in 1982 compared with 1972. But this rise seems to reflect increased financial risk induced by greater reliance on debt financing rather than any apparent increase in underlying business risk.

In contrast, industry decision makers identify increased political risk as adversely affecting overall business risk. Moreover, current pricing and fiscal regimes were seen as having contributed to a deterioration in the investment outlook.

The overall conclusion is that the investment climate for the Canadian petroleum production sector in 1982 was inferior to that in 1972.

EXECUTIVE SUMMARY

Over the decade since 1972, prices of Canadian oil and gas have on average risen at rates well in excess of the prevailing rate of inflation. This substantial 'real' increase reflects in large measure the rise in the world price of oil.

Such price behaviour suggests investment in the oil and gas production sector would have become progressively more attractive since 1972. But at the same time the Canadian oil industry has been subject to more complex and onerous fiscal regimes and to a greater degree of government control.

Questions arise about the impact of these events on industry profitability and on the minimum return required to justify new capital investment, often referred to as the 'hurdle' rate. A more fundamental question is whether the overall investment climate for Canadian oil and gas has become more or less attractive. These are the issues on which this study focusses.

Four key elements of investment behaviour which in combination determine the investment climate are

- — rates of return industry expects on new investments (expected rates of return)
- — rates of return industry has obtained on existing investments (achieved rates of return)
- — rates of return equity investors expect (capital market behaviour)
- — perceptions of the investment outlook by industry decision makers (industry perceptions).

These aspects are all examined in the context of 1982 compared with 1972. The choice of these two years is deliberate: 1972 precedes the dramatic increase in world oil prices in 1973-1974 yet it is after the period when these prices were dominated by downward pressures; 1982 was chosen because it was after the 1979-80 OPEC price hike, the introduction of the National Energy Program, and the September 1981 Alberta/Canada energy accord.

Expected Returns, 1972 Compared with 1982

Changes in the expected profitability of investment in hypothetical oil and gas reservoirs are assessed. A distinction is made between prolific and modest oil and gas reservoir production. Variations in inflation rates are eliminated by expressing results in real terms.

The analysis first looks at Alberta; to afford comparisons with international trends, returns are also evaluated for the North Sea (United Kingdom sector) and the United States (Texas). All evaluations were conducted on three bases: 'gross', 'stand alone', and 'ongoing'. 'Gross' means before deduction of taxes and royalties and thus estimates the 'social' return on reservoir investments. 'Stand alone' is after tax and royalty but with a project assessed on an entirely independent basis. 'Ongoing' takes account of whether a company can write off any excess tax deductions against other sources of income. Calculations are made of government takes as a proportion of 'resources generated', defined as gross revenue less costs.

No allowance was made for exploration and land acquisition costs. Exploration costs can seldom be assigned to individual reservoirs, but over the full petroleum investment cycle they must be covered. Land costs in the form of bonus bids represent a discretionary transfer of profit from a company to the resource owner.

Alberta

Real costs of reservoir development increased substantially between 1972 and 1982. Fiscal terms in 1972 were relatively simple, but by 1982 the tax regimes had become a lot more complex with additional emphasis on gross revenue type levies.

Oil Reservoirs: Gross returns were very much higher for 1982 compared with 1972, reflecting the rise in real oil prices during the period. Once account is taken of taxes and royalties the picture changes. On a 'stand alone' basis the expected rate of returns for a 'prolific' reservoir were much the same. The government take increased from 50 percent of resources generated in 1972 to 85 percent in 1982.

The rates of return on 'modest' sized oil reservoirs were more attractive in 1982 than in 1972, a result directionally consistent with the need to ensure increased taxes do not discourage development of lower quality deposits. For both sizes of reservoir, the increase in returns on an 'ongoing' basis is not substantial.

Gas Reservoirs: The rates of return in 1982 were lower than in 1972; the results also suggest the 1982 tax system was insufficiently sensitive to variations in reservoir quality. If gas production were deferred or reduced by virtue of market contraction, the impact on prospective returns would be substantial.

North Sea

Oil Fields: The relatively simple fiscal system for oil in 1972 had become much more complex by 1982. For both 'prolific' and 'modest' sized fields rates of return on investment varied little between 1972 and 1982, suggesting that changes in the fiscal regime and additional real costs of reservoir development have creamed off much of any additional economic rent created by the rise in world oil prices. A substantial difference exists between the 'stand alone' and 'ongoing' results, indicating the ability to take advantage of excess tax allowances could play a key role in luring investment.

Gas Fields: Returns in 1972 were unfavourably affected by price controls. By 1982 controlled prices had given way to a more market orientated regime which had a favourable impact on prospective returns.

Texas

The analysis was confined to oil and relates to both the outer continental shelf (OCS) and onshore West Texas. In Texas, mineral rights are privately owned and royalties are relatively modest. However, the State and the federal governments impose additional taxes, and by 1982 these tax systems had become more complex.

The results for Texas stand in sharp contrast to those for Alberta and the North Sea. Prospective returns are substantially higher in 1982 both for onshore and offshore oil reservoirs; government tax takes show only moderate increases, and even declines in some instances. However, exploration success is relatively low in these regions. Consequently, attractive returns are necessary to offset lesser likelihood of discovery. The improvement in returns in 1982 over 1972 means this feature has been recognized by a relatively benign fiscal system.

Returns Achieved on Existing Investments

A partial indication of changes in investment incentives over time is provided by rates of return disclosed by accounting information, after adjustment for inflation. Estimates of such real rates of return for the petroleum production sector in aggregate were made from 1972 to 1980, the last year for which comprehensive data were available. Calculations were also undertaken of returns achieved by the mining, utilities and total manufacturing sectors.

In the case of oil and gas, the 1970s saw increasing real rates of return, mainly reflecting rising prices and output, and the maturing of the industry. However, a downturn in real rates of return in 1980 was experienced even before the impact of the NEP. Other evidence suggests that returns fell further in 1981 before recovering somewhat in 1982. Estimates of these returns are especially sensitive to the definition of replacement costs. During the past decade petroleum industry costs have increased at rates well in excess of inflation. When account is taken of such additional replacement costs, real rates of return achieved erode quite dramatically.

Returns in the mining sector were more erratic than those from oil and gas production. Under regulation, returns for utilities are much more stable than those in mining and petroleum. Real returns in the manufacturing sector in the late 1970s were significantly below those in the earlier part of the decade.

Returns for the oil and gas production sector should be appreciably higher than those for utilities and total manufacturing, given the much higher risk to which this sector is exposed. This is indeed the case beyond the mid 1970s, but not in the early 1970s.

Rates of Return Required by Investors

The market behaviour of equity investments in Canada's oil and gas industry, 1972 compared with 1982, provides important information on changes in 'hurdle' rates of return and investor perceptions of risk. Risk was measured by calculating 'Beta' coefficients: the degree of fluctuation in the price of a stock divided by the corresponding degree of fluctuation in a suitable market index.

A distinction is made between overall business risk and financial risk, the risk relating to those company's assets financed by equity. If equity financing ratios fall, financial risk increases and consequently a higher equity rate of return will be required. Correspondingly, an 'equity' Beta depends both on the Beta of the firm's overall assets ('asset' Beta) and the firm's ratio of debt to equity. Thus, changes in the equity Betas over time may reflect variations in both underlying business risks measured by 'asset' Betas and financial risk.

The producing sector of the oil and gas industry was represented by a sample of companies, excluding integrated companies. Inter-industry comparisons of Betas were undertaken for metals and minerals, oil and gas (including integrated oils), industrial manufactured products and utilities.

The equity Beta of the average firm in the oil and gas company sample used exceeds that of the average TSE company by a wide margin, confirming that the oil and gas production sector is perceived by investors as being both more risky than the average industry and more risky than other sectors of the petroleum industry. The cost of equity capital was estimated by the Capital Asset Pricing Model (CAPM), which attempts to identify the relationship between the expected rate of return investors require on a security and its risk. In nominal terms the cost of equity capital increased by some six percentage points 1982 compared with 1972. Most of this is accounted for by higher inflation; the increase in the real cost of equity since 1972 is of the order of one percentage point. Estimates of 'asset' and 'equity' Betas suggest this increase reflects higher financial risk associated with a greater reliance on debt financing, rather than higher overall business risk.

Industry Perceptions

Industry decision makers' perceptions of the investment climate were gleaned from interviews with several industry executives. The issues reviewed were those relating to hurdle rates, taxation, incentives and pricing.

Although the concept of hurdle rates was treated by industry executives as rather ambiguous, there was a perception that they had risen in real terms in 1982 compared with 1972.

The general tenor of industry views was one of dissatisfaction and even disillusionment with many policies affecting the industry. To this degree, then, the present investment climate was seen as unfavourable, although the outlook for certain kinds of activities was seen as good, for example the search for new oil supplies in Western Canada.

The main counts against the current structure of policies, fiscal regimes and pricing in terms of investment decisions related to a perceived lack of stability, complexity, government intervention, the level and nature of tax takes and selective incentives.

The quite dramatic and continuing changes in government policies in recent times are seen as manifestly increasing industry risk. Investment is also inhibited by the sheer complexity of present regulations and taxation measures.

Interventionist policies that favour investment in certain regions may stimulate activity, but not in a way that would lead to a healthy investment climate. This is because economic imperatives are distorted and the 'efficiency' of investment is lower.

The returns extracted by governments from the industry have become excessive and the predominance of government takes based on gross revenues is seen as unfortunate. A system more oriented towards the taxing of profits was viewed as having a favourable impact on the investment environment.

Conclusions

The investment climate for the Canadian oil and gas is conditioned by expected returns in Canada and elsewhere, achieved returns, capital market behaviour and decision makers' perceptions. Expected real returns on individual Alberta reservoirs indicate the incentive to invest in new oil supplies may have improved somewhat between 1972 and 1982, but that for gas has deteriorated. This is in contrast to relative trends in Texas oil — where the improvement was very substantial — and for North Sea gas. Although real returns achieved by the oil and gas production sector in Canada rose substantially in the 1970s, significant reductions followed the introduction of the NEP. Achieved returns also fell markedly when account was taken of increasing replacement costs. Real returns required by equity investors in the oil and gas production sector were higher in 1982 than in 1972, a feature reflecting greater reliance on debt financing. Industry decision makers see higher political risks in 1982 compared with 1972, along with changes in pricing and fiscal regimes, as having adversely affected the investment outlook and increased 'hurdle' rates of return.

Overall, the investment climate for the Canadian oil and gas production sector was less attractive in 1982 than in 1972.

INTRODUCTION

Over the decade 1972 to 1982 the wellhead price of Canadian oil rose from an average of close to $3 per barrel to some $26 per barrel (August 1982 'old' oil price).After allowing for an inflation rate of 10 percent, the average annual 'real' rate of increase in oil prices was a substantial 13 percent or so. Price increases of comparable magnitude were recorded for natural gas. These trends, which in large measure reflect the substantial increase in the world price of oil, are in contrast to those in the 1960s, when oil and gas prices generally declined in real terms.

Ostensibly, such price behaviour suggests investment in Canadian oil and gas production over the past decade would have become progressively more attractive. However, at the same time the operations of the Canadian oil industry have become more tightly circumscribed by governments. Direct government control has been exerted over petroleum pricing. Taxation and royalty regimes have become more complex and onerous. Moreover, conflicts between different levels of government have been more intense, reducing the industry at times to a reluctant spectator of overlapping public claims on the industry's cash flow.

The industry observer may well ask what the upshot of all this has been on industry profitability and on the rate of return needed to attract capital investment in the Canadian conventional oil and gas production sector. Such a return is often referred to as the *hurdle rate*, the rate which industry decision makers perceive as the minimum required to justify undertaking new capital investment. Questions which come to mind are whether the 'hurdle' rate has increased over the decade relative to the overall rate of inflation, to corresponding rates of return in other Canadian industries and to earnings available from oil and gas investments elsewhere.

A more fundamental and broader question, which goes beyond the issue of hurdle rates, is whether the overall climate for investment in the Canadian oil and gas production sector is more or less attractive now than some ten years ago. If the climate has become less favourable, suggestions on policy initiatives to stimulate such investment and regain investor confidence become pertinent.

In analyzing complex issues, economists frequently adopt a simplified view of the 'real' world. A popular theoretical abstraction is that of perfectly competitive markets, which assumes perfect certainty, neutral taxation, and an absence of government intervention. In this environment new investment would take place up to the point at which the expected return on the last investment increment, the actual return achieved on it and the cost of capital required to attract investment funds would all merge. As a consequence, industry's overall 'hurdle' rate of return would be represented by the marginal cost of capital. Such a picture is, of course, a gross oversimplification in a world where foresight is often faulty, competition lacks 'perfection', capital markets need not function smoothly, taxation can be distortive, governments intervene and companies perceive and use 'hurdle' rates differently in making investment decisions.

However, the theory of perfect competition does help to identify certain key elements of investment behaviour which, in combination, condition what we have termed the investment climate, namely

- — the rates of return industry expects to earn on new investments (expected rates of return)
- — the rates of return industry has enjoyed on existing investments (achieved rates of return)
- — the rates of return company investors expect in the light of perceived risks (capital market behaviour)
- — the perceptions of the investment outlook by people involved in making actual investment decisions (industry perceptions).

For this reason, the analysis in this study focusses on these four key determinants of investment — expected returns, achieved returns, capital market behaviour and industry perceptions — all of which contribute not only to the formulation of industry 'hurdle' rates of return but also to the overall environment within which investment decisions are made.

It is important to recognize that the determinants are all inter-related. Expected rates of return will translate to some degree into actual returns, depending on predictive accuracy. Actual returns will condition expectations and the ability to undertake new investment. Capital markets and investment behaviour will also be affected by the relationship between expectations and achievement. Industry perceptions will reflect all aspects: anticipated investment performance as tempered by experience; information on the cost of capital revealed by investor behaviour; and also the government policy environment within which the industry operates.

The analysis is conducted in the context of comparing 1972 with 1982. The reason for choosing 1972 as the year on which to hinge comparisons is that it preceded the dramatic increases in world oil prices engineered by OPEC in 1973-74, with the associated policy dilemma they presented for Canadian governments. Yet 1972 is after the period when crude oil prices were dominated by downward pressures on world markets, as in the 1960s.

The year 1982 was chosen because it followed both the 1979-80 OPEC price hike and the introduction of the National Energy Program in October 1980. It also reflected the return to relative stability in Canadian energy policy embodied in the September 1981 Alberta/Canada accord. Further, the world oil market had become more quiescent.

The study focuses on investment in the conventional oil and gas production sector. Investment in activities which have quite different characteristics, such as synthetic oil plants, pipelines, refineries and the like was specifically excluded.

The four chapters of the study parallel the four main determinants of investment behaviour already identified. Chapter 1 deals with the expected profitability of investment in conventional oil and gas reservoirs 1972 compared with 1982. Hypothetical reservoirs are defined, differentiated by type (oil or gas) and size. The reservoirs are assumed to be brought on production first in 1972 and, then, in 1982. The evaluation in each year takes place under the respective 1972 and 1982 pricing and taxation regimes and incorporates relevant expectations on prices, costs and inflation. Expected returns — after adjustment for inflation — are calculated, as well as the present values of the various revenue, cost, tax and royalty streams. The analysis initially focusses on Alberta, but since the oil and gas industry operates internationally, relative changes in returns over time afforded by investments in competing jurisdictions are relevant. This dimension is covered by examining returns in 1982 compared with 1972 on typical oil and gas reservoir investments both in the North Sea (U.K. sector) and in the United States (Texas).

Chapter 2 relies on accounting information as the basis for analysis of actual returns the oil and gas production sector has achieved in aggregate. These results are compared with returns earned by other industries. All returns are expressed in 'real' terms by making appropriate adjustments to the accounting data to eliminate the impact of inflation.

Chapter 3 examines changes in risk and in required returns on equity as registered by investor perceptions. The evidence examined relates to how the stock markets have viewed changes between 1972 and 1982 affecting Canada's oil and gas production sector. The approach employed relies on stock market behaviour to estimate measures of risk and the cost of equity capital to different industry groups.

Chapter 4 relates to perceptions by industry of the investment outlook, based on information gleaned from interviews with industry executives. The Chapter also covers industry views on various policy issues relating to the investment climate governing the Canadian oil and gas production sector.

Technical details supporting the analysis reported here are published separately as Appendices in an Appendix Volume.

Chapter 1

PROFITABILITY OF OIL AND GAS RESERVOIR INVESTMENTS

Emphasis was laid in the Introduction on 'expectations' as a key element in making investment decisions. At any given point in time the level of expected returns determines whether an investment in a long-lived asset such as a petroleum reservoir is sufficiently attractive or not. In this sense, then, actual outcomes are irrelevant to the investment *decision*, although variations between actual and expected outcomes may well affect both the ability of a company to undertake further investments and how its expectations are formed. However, this a separate issue.[1] Our concern in this chapter is with *expected* profitability and especially with changes in expected profitability of individual petroleum reservoirs, 1972 compared with 1982.

Since results may differ according to the 'quality' of a deposit, we look at hypothetical reservoir configurations characterized as 'Prolific' and 'Modest'. We also distinguish between oil and gas reservoirs, given differences in pricing and fiscal arrangements that may apply between these hydrocarbons.

It is also desirable to define profitability after adjusting for variations in rates of inflation between the periods. After all, a rate of return in 1972 of, say, 12 percent, when inflation was running at some 4 percent is not the same as a return of 12 percent in 1982 when inflation was running at 10 percent. Expression of results in 'real' terms attempts to compensate for the impact of general inflation and allow proper comparisons between periods on an 'inflation free' basis.

In terms of Canada, our attention is restricted to Alberta.[2] An international dimension is added by looking at the profitability of reservoir investments in the North Sea (United Kingdom sector) and in the United States (Texas),[3] 1972 compared with 1982.

We emphasize that the purpose of including material on the North Sea and Texas is mainly to provide additional perspective on relative changes through time and not to indulge in comparisons of absolute returns between different jurisdictions.

For each region, then, we estimate reservoir profitability according to the criteria illustrated below:

Year	Oil	Gas
1972 Perspective	prolific	prolific
	modest	modest
1982 Perspective	prolific	prolific
	modest	modest

In what follows below, first we discuss the general technique used to calculate expected reservoir profitability in real terms. The next three sections deal with the underlying assumptions and results for the three regions examined: Alberta, the North Sea (United Kingdom sector) and Texas (onshore and offshore). A final section draws some overall conclusions.

1.1 Technique to Estimate Expected Profitability

First we choose the various pertinent physical reservoir parameters, according to size and whether the deposits are oil or gas. Next the expected profitability of each reservoir is determined according to the 1972 pricing and taxation regimes and given expectations about costs, prices and inflation prevailing then. We call this the '1972 Perspective'. The analysis is then repeated for precisely the same physically endowed reservoirs but on the assumption they would be developed and produced under the pricing and taxation regime and expectations appropriate for 1982. We call this the '1982 Perspective'.

Some of the information in which we are interested involves dollar quantities rather than rates of return. To afford proper comparison over different time periods we need to adjust quantities denominated in 1972 dollars to equivalent 1982 dollars. We make these general adjustments by applying the Gross National Expenditure (GNE) price index to 1972 dollar quantities. In this way we allow for variations in the general purchasing power of money over the ten year interval examined.

The sequential steps involved in the analysis are illustrated below for the case of a hypothetical reservoir developed in 1972.

1. Set the physical reservoir parameters — its reserves, time profile of production and the number and pattern of wells drilled.
2. Assign well and certain ancillary costs and operating costs over time, reflecting expected rates of inflation.
3. Estimate expected prices.
4. Compute taxes and royalties, given expected revenues and costs and the prevailing tax regime.
5. Compute expected *nominal* rates of return before and after taxes and royalties.
6. Apply price deflators derived from expected rates of inflation to convert expected nominal flows of revenues, costs, taxes and royalties to quantities expressed in 1972 dollars.
7. Calculate expected *real* rates of return and real present values.
8. Convert 1972 dollar figures to 1982 dollars by applying the GNE price index.

This basic procedure is applied to all the hypothetical reservoirs evaluated for the three regions examined: Alberta, the North Sea and Texas. Overall, such analysis of reservoir profitability provides essential information on the relative impact of changes in fiscal regimes, costs and expectations over the 1972-1982 interval.

1.2 Alberta

The analysis for 1972 was undertaken using a model of the 1972 petroleum production sector fiscal regime developed by DataMetrics Limited. Analysis for 1982 employed the well known POGO system of economic evaluation. The description below first comments on the data used; we then summarize the results and assess their implications. Full details are provided in the Appendix Volume, Appendix A.

1.2.1 Some Data Highlights

Table 1.1 shows the key assumptions made about the configuration and costs of the hypothetical Prolific and Modest oil reservoirs. The Prolific oil reservoir is five times as large as the Modest pool; the corresponding ratio for gas is eight. Peak output for the Prolific oil reservoir is about three times that of the Modest one; peak output for the gas reservoirs is proportional to reserves.

Development costs per unit of (peak) output for the Modest oil or gas reservoir are about 2.5 times greater than those for the relevant Prolific one, for both the 1972 and 1982 Perspectives. The increase over the decade in real costs of reservoir development was substantial; for oil it was some 80 percent. This means that on average such costs were increasing annually at a rate some six percentage points in excess of the prevailing inflation rate. These numbers reflect industry experience.

Price expectations are a key feature governing the investment outlook. For the 1972 Perspective, expected Alberta oil prices were treated as directly related to world prices. Based on representative projections of world prices made in 1972 (see Stanford Research Institute (1972)), oil prices were seen as rising in real terms until they reached a plateau in the mid 1980s. The 1982 Alberta oil pricing regime identifies various categories of oil, but in the context of new investments the relevant one is the new oil reference price (NORP). NORP is predicated on world oil prices, and we assume this treatment holds for the period of analysis. We characterize 1982 expectations for world prices as slightly falling in real terms to the late 1980s, then increasing to a plateau by the mid 1990s. Note that the initial 1982 price of some \$43/barrel (\$268/m3) is several order of magnitudes higher than the corresponding 1972 price of some \$3/barrel or \$7.50/barrel (\$47/m3) in 1982 dollars.

In terms of natural gas, future real prices for the 1972 Perspective were anticipated to increase by over 4 percent per year for the first decade to reflect a tighter gas market; the second decade was expected to have little real growth (an average of only 0.3 percent per year) as frontier natural gas supplies were expected to be onstream. The 1982 gas pricing regime is complex, involving differentials between domestic and export prices, with the producer price calculated as a weighted average. Representative projections in 1982 anticipated an eventual phasing out of exports and a closer correspondence between domestic and export prices. The expected average rate of increase in real gas prices under the 1982 Perspective was 2.3 percent to year 2001. As for oil, the 1982 benchmark gas prices were considerably higher than those for 1972. No allowances were made for any net wellhead values from gas byproducts.

TABLE 1.1

Summary of Alberta Hypothetical Reservoir Data
(dollar figures are Canadian dollars)

	Oil		Gas	
	Prolific	Modest	Prolific	Modest
Reserves	100 MM bbls (16 $10^6 m^3$)	20 MM bbls (3.2 $10^6 m^3$)	180 BCF (5.1 $10^9 m^3$)	22 BCF (620 $10^6 m^3$)
Peak Output	8,100 b/d (1294 $10^3 m^3$/d)	2,800 b/d (444 $10^3 m^3$/d)	25 MMCF/d (705 $10^3 m^3$/d)	3 MMCF/d (85 $10^3 m^3$/d)
Pre-Production Development Period	1 year	1 year	1 year	1 year
Production Decline Rate	10%	10%	10%	10%
Development Costs (1982 $, per unit of peak output)				
— 1972 Perspective	$3575 per b/d	$8740 per b/d	$641 per Mcf/d	$1,592 per Mcf/d
— 1982 Perspective	$6350 per b/d	$15600 per b/d	$990 per Mcf/d	$2,460 per Mcf/d
Annual Operating Costs (1982 $)				
— 1972 Perspective	$36,100/well	$31,200/well	$36,300/well	$27,500/well
— 1982 Perspective	$53,100/well	$44,500/well	$53,500/well	$39,500/well
Number of Wells	50	50	10	10

Source: Appendix Volume, Appendix A, Tables A.1 and A.2.

Expected rates of inflation for the 1972 Perspective were set at 3 percent. The 1982 Perspective involved much higher expected rates of inflation: 9 percent in 1983, declining thereafter to 6.5 percent over the long run.

The fiscal terms for oil and gas in 1972 were relatively simple, consisting of straightforward fixed percentage royalties, depletion allowances and standard corporate income tax.

By 1982 the tax regime had become convoluted. Provincial royalties differentiated between 'old' and 'new' oil and were non- deductible for federal income tax purposes, and a new gross revenue tax — the Petroleum and Natural Gas Revenue Tax (PGRT) — had been imposed. Furthermore, Petroleum Incentive Program (PIP) grants to subsidize wells drilled had been introduced, depending on a firm's degree of Canadian ownership.

1.2.2 Results — Oil Analysis

The results for the Alberta oil reservoirs are summarized in Table 1.2. Under the 1972 and 1982 Perspectives each reservoir was evaluated first on what we call a 'gross' basis, that is before taxes and royalties. In essence this shows the social return on the reservoir investment, where the social return comprises the sum of the private returns plus all taxes and royalties.

Second, the evaluation was conducted on a 'stand alone' basis, and third, on an 'ongoing' basis. 'Stand alone' as the term implies means the project was assessed as an entirely independent entity, irrespective of the overall taxation status of a company. In contrast, 'ongoing' takes account of whether a company can enjoy immediate benefits by applying tax deductions, which would otherwise be carried forward, against other sources of income.

Under the 1982 Perspective, the results shown are for a company enjoying a 100 percent Canadian Ownership Rating (COR). The returns for a company with foreign ownership having a zero COR are of course lower, but only to the extent of some 3 to 5 percentage points. Thus the COR rating does not appreciably affect comparisons between 1972 and 1982 at the reservoir development stage.[4]

In all cases the present values shown are calculated using a 10 percent real after tax discount rate.[5] Some support for using a rate in the region of 10 percent is provided by estimates of the real cost of equity capital for the oil and gas production sector in Chapter 3 which show figures ranging from 11 to 13 percent.[6] However, a suitable long-run discount rate for evaluating reservoir investments would tend to be somewhat higher to compensate for the costs of unsuccessful ventures (also see discussion on exploration costs below).

TABLE 1.2

Expected Real Returns from Alberta Oil Reservoir Investments under 1972 and 1982 Perspectives

	Prolific Reservoir		Modest Reservoir	
	1972	1982*	1972	1982*
Internal Real Rate of Return (%)				
A. Pre Tax and Royalty	68.9	229.6	22.0	88.5
B. After Tax, Stand Alone	47.0	49.8	13.1	26.2
C. After Tax, Ongoing	51.9	52.4	17.7	27.2
Net Present Value @ 10% Discount Rate ($MM, 1982$)				
A. Pre Tax and Royalty	102.0	574.1	14.4	165.1
B. After Tax, Stand Alone	47.4	89.1	3.0	29.6
C. After Tax, Ongoing	48.7	89.8	6.3	29.8
PV Tax Take as % of PV Resources Generated**				
A. Pre Tax and Royalty	n/a	n/a	n/a	n/a
B. After Tax, Stand Alone	53.6	84.5	79.2	82.1
C. After Tax, Ongoing	52.3	84.4	56.3	82.0

* Assumes 100 percent COR.

** PV Resources Generated = Present Value at 10 percent of Gross Revenue less Development Cost less Operating Cost.

n/a = not applicable

Before assessing the results we make some general comments on the economics of oil and gas supply.

(a) Pricing, supply and economic efficiency

The numbers cited earlier show that the rise in Alberta oil and gas prices between 1972 and 1982 was dramatic, amounting to some five fold in real terms. Rising resource prices have the key function of making higher cost oil and gas supplies economic to discover and develop. Accordingly, in the absence of changes in fiscal levies the profitability of a reservoir developed in 1982 would be very much higher than that of the same reservoir developed in 1972. It is hardly surprising, then, that additional taxes and royalties have been levied by governments seeking to cash in on higher returns enjoyed by established reservoirs. It is, though, important to ensure such increased government takes do not reduce profits on leaner new deposits to a degree that they become uneconomic. In other words, a general efficiency objective of government levies is to recognize reservoir quality: the lower the quality, the more lenient the levy.

As discussed, the analysis proceeds by examining profitability at the development stage for precisely the same quality of reservoir, 1972 compared with 1982. The argument can be made that if real after tax expected returns between the periods were the same, the inducement to invest — other things equal — would not have altered. But when prices rise, after tax expected returns for equivalent quality deposits should increase if the inducement to invest in more costly supplies were not to be impaired. This is because the additional cash flow will provide funds for investment in new, more expensive supplies.[7] It will also indicate that returns on higher cost sources are improving even if fiscal regimes were not well calibrated by deposit quality. Furthermore, improved reservoir returns will offset the higher costs of exploration, successful or otherwise, that the search for less accessible and more difficult prospects will entail.

In short, economic efficiency requires supply to respond to rising prices, a response that will be signalled by higher returns on equivalent deposits between periods. If such returns show little significant variation, the incentive to add new higher cost supplies would have diminished and thus the investment climate would have deteriorated.

(b) Prolific oil reservoir

The internal rates of return (IRR'S) and net present values for the pre tax and royalty evaluation — the 'gross' assessment — show a much greater 'social' return for the 1982 Perspective compared with 1972, as period (although the rise was partly offset by increasing real costs) and always assuming government policy allows the 1982 reservoir to continue to enjoy world oil equivalent prices throughout its life.

Once account is taken of taxes and royalties, the picture changes. The expected real return was slightly higher in 1982 for the 'stand alone' case, but much the same on an 'ongoing' basis. (For the zero COR case the real rate of return was somewhat lower than in 1972.) However, at a 10 percent (real) discount rate, net (real) present values are some 75 per cent higher under the 1982 Perspective than in 1972, and under a net present value investment criterion returns have improved as long as the real 'hurdle' rate employed for discounting of, say, under 20 percent is much the same between the two periods.[8]

To illustrate relative tax burdens, calculations have been made of the present value tax take as a proportion of what we call resources generated, defined as present value gross revenues less development and operating costs, an approximation to the amount of economic rent available."

As might be expected, the aggregate tax take has increased from around 50 percent of resources generated in 1972 to 85 percent under the 1982 Perspective, showing that much of the substantial additional (real) economic rents arising from higher oil prices in 1982 have been absorbed by the tax and royalty system, one way or another. In undiscounted terms, real gross revenues in 1982 compared with 1972 (stand alone) were up some four times while the total tax take rose about eight times; at the same time, real development costs doubled.

(c) Modest oil reservoir

Similarly to the Prolific reservoir, the Modest reservoir shows a very substantial increase in 'gross' returns in 1982 compared with 1972, a lot of which is then absorbed by higher royalties and taxes. However, the rates of return on either a 'stand alone' or 'ongoing' basis are substantially more attractive in 1982 compared with 1972, notwithstanding a markedly higher tax bite. This illustrates the leverage effect of higher prices on rates of return, despite tax hikes, when base returns are at low levels. The result is consistent with the need in 1982 to ensure increased tax burdens do not discourage the development of lower quality resources, a priority to which Alberta's production- sensitive royalties contribute, in contrast to the rigid character of the PGRT.

(d) Ongoing results

For both sizes of reservoirs the ability to apply tax allowances against other sources of taxable income (the ongoing assumption) does produce a favourable increase in rates of return and present values. However, we note that these tax provisions do not produce such a sizeable swing in results as in different jurisdictions such as the North Sea (see Section 1.3 below).

We caution that while expected rates of return for less well endowed oil reservoirs seem to have improved somewhat in 1982 compared with 1972, this does not of itself signify an improved climate for investment. Such additional returns for given reservoirs may be offset by increases in perceived risks — political or otherwise — as reflected by higher 'hurdle' rates of return, by increased exploration costs(discussed below) or by sharply rising marginal development costs of new supplies.

(e) Impact of land aquisition costs

Land costs arise in the form of payments for exploration permits and licences, Crown drilling reservations and production leases, and land rentals. Land rentals are included in the operating expenses used in the reservoir evaluations discussed earlier. But none of the results listed in Table 1.2 allow for the costs of acquiring exploration and production rights.

The main vehicle of acquisition is the land bonus bid. Inclusion of bonus bids would raise the government take in both years, and because bonus bids are predicated on expected economic rents they would in part absorb any differentials in expected profitability between 1982 and 1972. Indeed, if title to all of the lands underlain by a reservoir were acquired by competitive bids, and if competition were intense, the expected real rates of return on reservoirs would tend to equalize between periods, assuming the after tax discount rates used in formulating bids did not vary.

In this light, then, fluctuations over time in land acquisiton costs represented by bonus bids are evidence of variations in the intensity of competition and in expected profitability. Other things equal, the higher the level of expected profits, the higher the bonus bids. Thus increasing land costs in the form of bonus bids are not evidence of industry labouring under an additional tax burden but, rather, indicate enhanced profits transferred to governments.

Proper comparison of land acquisition costs over time would require a time series on bids for the same property, adjusted for any differences in competitive conditions. Such theoretically ideal data are virtually unobtainable. However, some calculations have been undertaken of average land bonus bids per unit of reserves discovered which suggest that by 1979 such costs for oil were some 50 percent higher in real terms than in 1972, while those for natural gas over the same period almost doubled.[10]

These figures indicate land acquisition costs in real terms for the average reservoir would be higher in 1982 than in 1972, thereby increasing the (provincial) government take and reducing any positive spread between expected real returns and net present values in 1982 compared with 1972. Increases in land acquisition costs are also consistent with the estimates of higher gross returns calculated beforehand for 1982 over 1972, indicating a greater surplus available for absorption by bonus bids.

(f) Impact of exploration costs

Conventional exploration costs consist of geological and geophysical work and the drilling of both dry and successful exploratory wells. The results tabulated beforehand do not identify and allow for exploration expense by reservoir because such costs are seldom reservoir specific. Rather, the knowledge generated by exploration activity applies in general to the relevant geological formation which may contain both oil and gas. Thus information provided by any individual exploratory input — whether the drilling of a well or the results of a seismic program — can apply to several oil and gas reservoirs and even over a whole exploration basin. But over the entire investment cycle, a compnay must cover exploration costs and earn a return on them.

In terms of comparing 1982 with 1972, the likelihood is that the real unit cost of exploration inputs rose. This would be consistent with the real cost increases recorded for development and operating expenses (see Table 1.1). There is also the question of whether 'prospectivity' — the chances of success has changed significantly over the decade. If the industry's ability to find oil deteriorates, exploration costs will be higher even if the real unit cost of exploratory inputs were constant. At any rate it is highly likely that the real expenditures required to make a discovery were higher in 1982 compared with 1972, and hence any improvement in prospective returns in 1983 may have been absorbed — or more than absorbed — by higher exploration expenses.

While it is not feasible to definitively allocate exploration inputs to individual reservoirs, some insight on the impact of exploration costs can be obtained by allowing for them on an average basis. Accordingly, we attributed a measure of average exploration costs to each oil reservoir and repeated the economic evaluations.

The average exploration cost allowance for each size of reservoir was estimated employing information on finding costs[11] for average sized reservoirs adjusted on the assumption that a prolific reservoir would be more difficult to find than a modest sized one. The resulting exploration cost allowance for the two hypothetical reservoirs doubled in real terms between 1972 and 1982. The impact on profitability of allowing for exploration costs is substantial. For the prolific reservoir the 'ongoing' rate of return approximately halves for both the 1972 and 1982 Perspectives. The relative impact 1972 versus 1982 is dependent on COR ratings, with exploration costs for a company enjoying a 100 percent COR rating having a somewhat lesser effect in 1982 compared with 1972 by virtue of PIP subsidies. Much the same pattern of results after allowing for exploration is shown for Modest sized reservoirs, but the expected returns indeed become modest, suggesting that economic incentives to discover and develop lower quality reservoirs are weak.

(g) Impact of alternative price and cost expectations

All the results discussed so far are of course dependent on the choice of price and cost projections and, to a lesser extent, on inflation expectations. To examine the sensitivity of the results to changing expectations we adjusted the 1982 Perspective to outlooks more appropriate for 1983. Inflation expectations were dampened in the near term, the real price of world oil was expected to drop further and recover later than had been foreseen in 1982, and on the other hand reservoir development costs were projected to decline in nominal dollars from the 1982 levels.

Under the alternate price expectations the gross return for the Prolific reservoir 100 percent COR case (comparable to the 230 percent real shown in Table 1.2) would be 176 percent real; the real after tax (ongoing) return would be 48 percent (compared to 52 percent in Table 1.2). Thus for the Prolific reservoir, the slight improvement in after tax rate of return was dependent on an optimistic set of price expectations which are not so far materializing.

1.2.3 Results — Gas Analysis

We have already discussed the gas reservoir data and expectations about prices and costs in the preceding review of the assumptions and basic data employed in the case of oil (see commentary on Table 1.1). Here we review the results of the gas reservoir investment analysis listed in Table 1.3.

TABLE 1.3

Expected Real Returns from Alberta Gas Reservoir Investments under 1972 and 1982 Perspectives

	Prolific	Reservoir	Modest	Reservoir
	1972	1982*	1972	1982*
Internal Real Rate of Return (%)				
A. Pre Tax and Royalty	61.4	157.7	20.8	53.6
B. After Tax, Stand Alone	42.5	39.8	10.9	9.0
C. After Tax, Ongoing	47.1	41.6	14.9	9.4
Net Present Value @ 10% Discount Rate ($MM, 1982$)				
A. Pre Tax and Royalty	57.0	209.0	2.6	18.9
B. After Tax, Stand Alone	26.8	30.5	0.2	-0.3
C. After Tax, Ongoing	26.7	30.8	0.9	-0.1
PV Tax Take as % of PV Resources Generated**				
A. Pre Tax and Royalty	n/a	n/a	n/a	n/a
B. After Tax, Stand Alone	53.1	85.4	92.6	101.4
C. After Tax, Ongoing	33.4	86.8	67.5	108.8

* Assumes 100 percent COR.

** PV Resources Generated = Present Value at 10 percent of Gross Revenue less Development Cost less Operating Cost.

n/a = not applicable

In Table 1.3 the 1982 results apply to a company with a 100 percent Canadian Ownership Rating (COR). As for oil reservoirs, the COR rating does not have an appreciable effect on returns at the reservoir development stage, but becomes more influential if exploration costs were included.

(a) Prolific reservoir

The 1982 Perspective yields a substantially greater amount of surplus available for governments to absorb in their role as resource owners (provincial government) or general leviers of taxes (federalgovernment). However, the after tax rates of return whether 'stand alone' or 'ongoing' are lower in 1982, but the net present values at a 10 percent discount rate are somewhat higher. Correspondingly, the tax take in 1982 is very much higher at around 85 percent whether stand alone or ongoing compared with some 53 percent (stand alone) and 33 percent (ongoing) in 1972. Put another way, in terms of both the internal rate of return (IRR) and net present values, the 1982 tax and royalty system extracts a far greater proportion of any economic rent than does the 1972 system. As we shall see below, this effect becomes more pronounced in the case of the modest sized reservoir.

(b) Modest reservoir

'Gross' rates of return and net present values are much higher under the 1982 Perspective. For example, at a 10 percent discount rate such a surplus under the 1982 Perspective is some 7 times that in 1972. But the tax take increases 7.6 times (discounted at 10 percent). Consequently, while the after tax rate of return under the 1972 Perspective is sustained at barely respectable levels (about 15 percent on an ongoing basis), returns under the 1982 Perspective are unattractive. At a 10 percent discount rate the tax take becomes greater than 100 percent. In other words the 1982 tax system would absorb more economic rent than expected to be generated and, under the cost and revenue assumptions adopted, the lower quality gas reservoirs would tend to be rendered uneconomic.

These results suggest that the 1982 tax system is not sufficiently sensitive to variations in reservoir quality, making poorer quality gas reservoirs which nevertheless provide an excess of social benefits over social costs unattractive on a commercial basis.[12] Again, the results take no account of full cycle costs. Since exploration costs were higher in real terms in 1982 than in 1972, their inclusion would accentuate the deterioration in the 1982 picture, unless their impact were sufficiently mitigated by PIP grants.

No adjustment has been made under the 1982 Perspective for possible problems in marketing gas after a reservoir has come on stream. If production were deferred or were at lower levels than anticipated, the impact on returns would be strongly adverse. Specifically, either a one year delay or a 50 percent cut in the first two years of production reduces the internal rate of return to three quarters of its previous level. In short, marketing problems early in the reservoir life have a strong impact on project viability.

Before looking at returns available in other jurisdictions, we make some brief comments on two structural aspects of the 1972 and 1982 taxation regimes as revealed by the preceding results for both oil and gas. First, the share of total taxes and royalties paid over a reservoir life is markedly higher in the first five years of operation under the 1982 system compared with the 1972 regime. In other words, the 1982 fiscal system compared with 1972 is relatively front end loaded, a feature that holds irrespective of reservoir type (oil or gas) or size, or whether the analysis is conducted on a stand-alone or ongoing basis. Second, a greater share of the government tax take is obtained by gross revenue taxes under the 1982 fiscal system, compared with 1972, especially for prolific oil and gas reservoirs.[13]

1.3 North Sea (United Kingdom Sector)

The analysis summarized here was conducted primarily by Alexander Kemp and David Rose of the University of Aberdeen, Scotland, using models they have developed to characterize North Sea investments. The discussion below proceeds by reviewing the data employed, then summarizes the results and reviews their implications. Full details of the analysis are provided in the Appendix Volume, Appendix B.

1.3.1 Data Highlights

Key features of the hypothetical Prolific and Modest oil and gas North Sea fields are brought together in Table 1.4.

The Prolific oil field is assumed to be five times as large as the Modest deposit; the corresponding multiplier for gas is four. Peak oil output for the Prolific deposit is somewhat over four times that for the Modest one. The level of peak output for the Prolific gas field is four times that for the Modest field — precisely the same ratio as that for reserves.

In 1972, lack of experience in oil reservoir development in the North Sea made development costs quite uncertain. Accordingly, two levels of oil development costs were assumed, termed 'optimistic' and 'pessimistic'. The results shown here relate to the optimistic costs.[14] In the case of gas, the availability in 1972 of a fair degree of development experience made expected development costs more certain.

Real costs of development in 1982 for an identical oil reservoir have risen very markedly over 1972; the increase for gas fields is a good deal less.

Details on world oil price expectations for the 1972 and 1982 Perspectives were given in the discussion of Alberta reservoirs beforehand. In essence, the rate of growth derived from these projections was applied to the respective initial North Sea prices.

The inflation outlook was much more subdued in 1972 than in 1982, with long term inflation in the United Kingdom expected in 1972 to settle down at 3 percent, while the corresponding expectation in 1982 was set at 6 percent.

TABLE 1.4

Summary of North Sea Hypothetical Field Data
(dollar figures are U.S. dollars)

	Oil		Gas	
	Prolific	Modest	Prolific	Modest
Reserves	500 MM bbls (79 $10^6 m^3$)	100 MM bbls (16 $10^6 m^3$)	3 TCF (85 $10^9 m^3$)	0.75 TCF (21 $10^9 m^3$)
Peak Output	140 M b/d (29 $10^3 m^3/d$)	42.5 M b/d (6.8 $10^3 m^3/d$)	660 MMCFD (19 $10^6 m^3/d$)	165 MMCFD (5 $10^6 m^3/d$)
Pre Production Development Period	5 years	5 years	2 years	2 years
Production Decline Rate	16 %	23%	20%	20%
Development Costs (1982 \$, per unit of peak output)				
— 1972 Perspective	\$10,600 per b/d	\$12,400 per b/d	\$1,490 per Mcf/d	\$1,915 per Mcf/d
— 1982 Perspective	\$20,000 per b/d	\$30,000 per b/d	\$2,131 per Mcf/d	\$2,744 per Mcf/d
Annual Operating Costs	5% of Accumulated Dev. Costs	6% of Accumulated Dev. Costs	5% of Accumulated Dev. Costs	6% of Accumulated Dev. Costs

Source: Appendix Volume, Appendix B.

The fiscal terms for United Kingdom oil in 1972 were relatively simple, comprising a tax deductible royalty of 12 1/2 percent and corporation tax at 52 percent; development costs could be written off at 100 percent in the first year.

By 1982 the tax regime had become very complex. A petroleum revenue tax (PRT) was levied at 75 percent of gross revenues. But various offsetting allowances were permitted. Development costs could be written off at a rate of 100 percent plus a premium or 'uplift' rate of 35 percent. An annual oil allowance of certain stipulated quantities could be taken 'tax free'. Moreover, a 'safeguard' provision constrained the effective PRT rate to lower levels if gross profits were slow in recovering accumulated investment. Royalties were deductible from PRT, and PRT and royalties were deductible from corporation tax. But in addition an advance PRT (APRT) was levied for five years, from which again an oil allowance was deducted.

The taxation regime for natural gas in each of the two years was similar to that for oil.[15]

1.3.2 Results — Oil Analysis

Table 1.5 summarizes the results for the North Sea oil fields. To parallel the Alberta analysis, the evaluation for each field under the 1972 and 1982 Perspectives was conducted on a 'gross' basis, that is pretax and royalty, then on a 'stand-alone' basis, and finally on an 'ongoing' basis. Again the distinction between the latter two situations concerns the ability of a company to write off tax deductions as they are incurred. 'Stand-alone' means a company does not have income against which to offset excess deductions. 'Ongoing' assumes a company can enjoy immediate benefits from surplus tax deductions by reducing tax payable on other sources of income. As we shall see, this facility has an important influence on expected after tax rates of return in the context of the North Sea.

Table 1.5 shows both expected internal rates of return (IRR's) and net present values for the respective oil reservoirs, discounted at 10 percent. It also shows the approximate proportion of the apparent economic rent absorbed by tax payments on a present value basis (at 10 percent).

(a) Prolific oil field

For the Prolific field, after tax net present values at a 10 percent discount rate rose substantially from 1972 to 1982. However, the after tax expected internal real rates of return are virtually the same between the 1972 and 1982 Perspectives, irrespective of whether the evaluation is carried out on a 'stand alone' or an 'ongoing' basis. This result emerges notwithstanding the significant increase in the gross returns in 1982 compared with 1972, a function largely of the six fold increase in real oil prices during this interval. The conclusion here is that the combination of changes in the fiscal regime and increasing real costs of reservoir development have creamed off much of any additional economic rents created by the substantial rise in world oil prices, at least if the real cost of capital or 'hurdle' rate of return were significantly above 10 percent. Correspondingly, the tax take as a proportion of resources generated — a measure of the resources available to be taxed — rose substantially between 1972 and 1982 as additional rent was appropriated by the government.

TABLE 1.5

Expected Real Returns from North Sea Oil Field Investments under 1972 and 1982 Perspectives

(dollar figures are U.S. dollars)

	Prolific Field		Modest Field	
	1972	1982	1972	1982
Internal Real Rate of Return (%)				
A. Pre Tax and Royalty	25.7	34.7	16.7	19.3
B. After Tax, Stand Alone	16.4	16.4	7.8	8.8
C. After Tax, Ongoing	27.5	27.0	17.5	18.1
Net Present Value @ 10% Discount Rate ($MM, 1982$)				
A. Pre Tax and Royalty	1158	3858	106	344
B. After Tax, Stand Alone	325	570	-26	-34
C. After Tax, Ongoing	542	931	50	132
PV Tax Take as % of PV Resources Generated*				
A. Pre Tax and Royalty	n/a	n/a	n/a	n/a
B. After Tax, Stand Alone	72.0	85.0	124.0	110.0
C. After Tax, Ongoing	53.0	76.0	54.0	62.0

* PV Resources Generated = Present Value at 10 percent of Gross Revenue less Development Cost less Operating Cost.

n/a = not applicable

A comparison of the stand alone and ongoing results shows the expected rate of return is strongly affected by whether companies have other income against which to claim 'surplus' tax allowances.

(b) Modest oil field

The internal rates of return for the Modest field on a 'gross' basis do not show the same degree of improvement, 1982 over 1972, as do those for the Prolific field. This outcome indicates the relatively stronger impact of rises in real costs of reservoir development in relation to real revenues for the 1982 Perspective over that for 1972.

On a stand alone basis, the rates of return on the Modest field are indeed modest. It also seems that while the real after tax return has increased somewhat under the 1982 Perspective — suggesting that the tax system has become somewhat more sensitive to less well endowed fields — nevertheless the economics of the Modest field remain marginal, at least for the stand alone case. In terms of present values (10 percent discount rate) the tax take absorbs more than the apparent surplus available after allowing for a 10 percent real return (after tax) on investment.

Again, the ability of a company to write off tax allowances against other income has a significant impact on expected rates of return, raising them to respectable levels for the Modest field, with little variation between the 1972 and 1982 Perspectives. Under the 1982 Perspective the tax take is significantly lower for the Modest field, indicating that at least on an ongoing basis the tax instruments are partly tuned to differences in resource endowments.

Overall, for oil the prospective rate of return on investment at the development stage seem to have changed little between 1972 and 1982, although net present values increased. This conclusion suggests the United Kingdom fiscal regime has effectively tended to absorb additional economic rents conferred by rising oil prices to an extent analogous to treating the industry as a regulated utility: a certain level of (real) profit would be allowed, but not more. But note that an ability to maintain real rates of return while inflation has increased markedly also shows that the fiscal system is sensitive to changes in the rate of inflation. The substantial difference between expected rates of return according to whether a project is on a 'stand alone' or 'ongoing' basis demonstrates that the availability of other income against which to claim tax allowances can play a key role in luring investment. Especially for poorer fields, it may make the difference between whether exploitation is commercial or not.

The analysis excludes the question of exploration costs. As discussed, exploration costs can only rarely be assigned in any precise way to individual reservoirs, but over the full investment cycle they must be covered.

In the North Sea, exploration costs are a relatively small fraction of overall expenditures, a reflection primarily of the high costs of development. In all likelihood, then, exclusion of exploration costs does not significantly affect the analysis.

A more important feature may be changes in 'prospectivity' — the probability of commercial success — 1972 over 1982. It is probable that prospectivity for oil was lower in 1982 than in 1972. This would have affected the willingness of companies to explore. Accordingly, while expected real after tax returns at the development stage may have been much the same in 1982 and 1972, full cycle prospective returns after allowing for exploration inputs may have been lower in 1982, if, as we suppose, exploration had become both more risky and more expensive in real terms.

1.3.3 Results — Gas Analysis

The basic data on gas fields have been outlined and discussed already (see Table 1.4), as have the respective 1972 and 1982 fiscal regimes. Here we comment on price expectations for North Sea natural gas. In the United Kingdom the British Gas Corporation (BGC) has acted as a monopoly buyer of gas from producers on the North Sea. In the 1960s and 1970s they endeavoured to fix prices reflecting 'fair' rates of return. Provision was made for some degree of price escalation if costs inflated — as they did — but full compensation were not awarded. For the 1972 Perspective, we characterize the expected controlled price — a monopsony pricing regime — by escalation of the 1972 price at 60 percent of the expected rate of inflation.[16]

In the 1982 context, gas price contracts generally provided for escalation at the same rate as competitive petroleum fuels. In short, market style pricing prevailed. Accordingly, expected gas prices were assumed to escalate at the same rate as expected world oil prices.[17]

The results for gas fields are summarized in Table 1.6; the Table format parallels that for oil reservoirs (Table 1.5). For both the Prolific and Modest fields, 'gross' returns are very much higher under the 1982 Perspective, primarily reflecting the substantial increase in real prices.

(a) Prolific field

For the 1972 Perspective on a 'stand alone' basis even the return on the Prolific field is slight if prices are expected to be controlled. The return improves markedly with market pricing under the 1982 Perspective. Again, the ability to enjoy immediate tax benefits has a substantial influence on the results. The 'ongoing' rate of return even under 1972 conditions reaches more respectable levels.

(b) Modest field

The picture for the Modest gas field is somewhat different. Under the 1972 Perspective, price controls render the deposit uneconomic. In contrast, under the 1982 Perspective the field becomes economic, especially on an ongoing basis. This improvement mainly reflects the adoption of market oriented pricing. There is also evidence that the tax system for natural gas in 1982 was more sensitive than that in 1972 to variations in reservoir 'quality'.[10]

Again, all these results exclude exploration costs and do not accommodate any differences in 'prospectivity', 1982 compared with 1972. However, it is not clear that prospectivity for gas fields changed during this interval. It is more likely that gas price controls caused a reduction in exploration in the 1970s. The recent big change in North Sea natural gas prices with the adoption of market pricing is likely the main factor explaining the recent upsurge in gas related exploration activity, rather than any change in perceived prospectivity.

TABLE 1.6

Expected Real Returns from North Sea Gas Field Investments under 1972 and 1982 Perspectives
(dollar figures are U.S. dollars)

	Prolific Field		Modest Field	
	1972*	1982	1972*	1982
Internal Real Rate of Return (%)				
A. Pre Tax and Royalty	14.6	35.8	6.6	27.5
B. After Tax, Stand Alone	6.5	16.6	0.2	14.4
C. After Tax, Ongoing	12.1	25.7	3.2	22.4
Net Present Value @ 10% Discount Rate ($MM, 1982$)				
A. Pre Tax and Royalty	222	2,782	-46	548
B. After Tax, Stand Alone	-124	371	-106	81
C. After Tax, Ongoing	47	577	-45	149
PV Tax Take as % of PV Resources Generated**				
A. Pre Tax and Royalty	n/a	n/a	n/a	n/a
B. After Tax, Stand Alone	155.8	86.7	***	85.3
C. After Tax,Ongoing	76.9	79.3	***	72.8

* Assumes gas prices remain controlled.

** PV Resources Generated = Present Value at 10 percent of Gross Revenue less Development Cost less Operating Cost.

*** No resources generated.

n/a = not applicable

1.4 Texas

The analysis for Texas is confined to oil, but relates to both the outer continental shelf (OCS) and onshore West Texas. As for the North Sea, the evaluation was undertaken mainly by Alexander Kemp and David Rose of the University of Aberdeen. Paralleling previous sections, the discussion below comments on the data employed, summarizes the results and reviews their implications. Full details are provided in the Appendix Volume, Appendix C.

1.4.1 Data Highlights

Summary data for the hypothetical Prolific and Modest sized oil reservoirs, offshore and onshore, are brought together in Table 1.7.

(a) Onshore (West Texas)

Reserves and peak production for the 'Prolific' reservoir were assumed to be some 5.5 times those for the Modest reservoir. Production from both reservoirs is assumed to begin by the end of the first year of development.

Development costs per unit of peak output for the Modest reservoir are about three times that for the Prolific. Operating costs per well are higher for the Prolific reservoir, reflecting its assumed greater depth. Costs in real terms have nearly doubled over the decade since 1972.

(b) Offshore

The Prolific reservoir reserves and production were assumed to be about 1.7 times those for the Modest one. Development of both reservoirs was assumed to take place over a three year interval; the reservoirs were assumed to be located at the same depth. Development costs per unit of peak output were about 1.6 times higher for the Modest compared with the Prolific reservoir. Costs in real terms increased by about 1.3 times over the interval 1972 to 1982.

The expectations of world oil prices in real terms for 1972 and 1982 were indexed and applied to appropriate 1972 and 1982 benchmark prices for Texas offshore and onshore, respectively. Expected inflation rates were set at 3 percent in 1972 and at 6.5 percent in 1982.

In Texas, mineral rights are privately owned and in 1972 royalties were 12-1/2 percent. The State imposed two production taxes; there was no State income tax. Federal income tax was levied; a depletion allowance and certain investment credits were allowed.

TABLE 1.7

Summary of Texas Hypothetical Oil Reservoir Data
(dollar figures are U.S. dollars)

	Onshore West Texas		Offshore	
	Prolific	Modest	Prolific	Modest
Reserves	3,090 M bbl (490 10^3m^3)	546 M bbl (87 10^3m^3)	32 MM bbl (5 10^6m^3)	18.5 MM bbl (3 10^6m^3)
Peak Production	1,229 b/d (195 m^3/d)	216 b/d (34 m^3/d)	12,000 b/d (1,907 m^3/d)	7,000 b/d (1112 m^3/d)
Pre-Production Development Period	less than 1 year		3 years	3 years
Production Decline Rate	15 percent	15 percent	15 percent	15 percent
Development Costs (1982 $ per unit of peak output)				
— 1972 Perspective	$2,667 b/d	$ 6,548 b/d	$5,867 b/d	$ 9,865 b/d
— 1982 Perspective	$4,944 b/d	$12,037 b/d	$8,000 b/d	$13,000 b/d
Annual Operating Costs (1982 $)				
-1972 Perspective	$ 8,600/well	$ 6,200/well	7% of accumulated development costs	
-1982 Perspective	$15,400/well	$11,200/well		

Source: Appendix Volume, Appendix B.

For the 1982 Perspective the royalty was 16-2/3 percent. Investment tax credits and accelerated depreciation were allowed. In addition to income tax, the Federal government imposed a (deductible) Windfall Profits Tax (WPT); this tax varied with the 'tier' to which oil was allocated. For the relevant category adopted here, it starts at around 25 percent and was assumed to be phased out by 1993.

1.4.2 Results of the Analysis: West Texas

Table 1.8 summarizes the results for the West Texas reservoirs. As for the other regions, the evaluations were conducted on a 'gross' basis—that is, before tax and royalties — then for the two post tax and royalty situations: 'stand alone' and 'ongoing'.

The Table shows both expected internal rates of return and net present values for the respective oil reservoir investments, discounted at 10 percent. It also shows the proportion of resources generated — an approximation for economic rent — absorbed by tax payments, on a present value basis (at 10 percent).

TABLE 1.8

Expected Real Returns from Oil Reservoir Investments in West Texas under 1972 and 1982 Perspectives

(dollar figures are U.S. dollars)

	Prolific Reservoir		Modest Reservoir	
	1972	1982	1972	1982
Internal Real Rate of Return (%)				
A. Pre Tax	58.4	133.8	22.0	63.0
B. After Tax, Stand Alone	41.0	90.8	12.7	38.5
C. After Tax, Ongoing	57.8	124.3	17.9	50.5
Net Present Value @ 10% Discount Rate ($MM, 1982$)				
A. Pre Tax	6.6	35.0	0.7	6.7
B. After Tax, Stand Alone	3.3	15.2	0.1	2.5
C. After Tax, Ongoing	3.7	15.7	0.3	2.8
PV Tax Take as % of PV Resources Generated*				
A. Pre Tax	n/a	n/a	n/a	n/a
B. After Tax, Stand Alone	49.6	56.5	80.8	60.5
C. After Tax, Ongoing	44.0	55.3	56.5	58.8

* PV Resources Generated = Present Value at 10 percent of Gross Revenue less Development Cost less Operating Cost.

n/a = not applicable

(a) Prolific oil reservoir

The 1982 Perspective 'gross' rates of return are about double those for 1972 — a function primarily of the increase in oil prices between the two years. Both the 'stand alone' and 'ongoing' basis returns double as well. And these real returns are very attractive, assuming the reservoirs can be found. Although the tax takes increase between the years, the addition is quite modest. On a stand alone basis it rises from some 50 percent in the 1972 Perspective to about 57 percent in 1982.[19] The spread between the stand alone and ongoing returns is significant, especially in 1982, indicating that successful reservoir development will be especially attractive for companies already in a tax paying position.

(b) Modest oil reservoir

The gross rates of return show an even greater relative improvement in 1982 compared with 1972 than those for the Prolific reservoir, almost tripling. The after tax returns on a 'stand alone' basis also triple. The result reflects the increase in oil prices, but more importantly it signifies a significant *reduction* in the tax take on a stand alone basis from some 80 percent in 1972 to 60 percent under the 1982 Perspective. The tax take in 1972 was certainly high — and the resulting rates of return correspondingly unattractive — but in 1982 the returns are greatly enhanced, indicating that the fiscal system has become much more accommodating in terms of lower quality reservoirs.

The 'ongoing' rates of return show the ability to write off excess tax deductions against income has quite a strong influence, particularly for the 1982 Perspective where the spread between the stand alone and ongoing results becomes as much as 12 percentage points. Notably, the relative tax take on an ongoing basis is much the same in 1982 as in 1972.

1.4.3 Results of the Analysis: Offshore

The results are summarized in Table 1.9 in the same format as other tables in this chapter.

(a) Prolific reservoir

The gross returns increase 2-1/2 times between 1972 and 1982, much the same proportionate increase as shown for the stand alone IRR's. This indicates the proportionate tax take has shown little variation. The ongoing returns are some 10 percentage points higher in both years than those for stand alone. This indicates the relative improvement in IRR's enjoyed by companies able to obtain immediate tax relief declined in 1982 compared with 1972.

The pattern of these results is quite similar to those for the onshore West Texas Prolific reservoir.

(b) Modest field

Under the 1972 Perspective the returns for the Modest sized reservoir are unattractive. The change under the 1982 Perspective is dramatic. Gross real rates of return increase four-fold, and because about half of these incremental returns are left in the hands of companies the stand alone real returns increase six fold, from subcommercial levels of 7 percent under the 1972 Perspective to in excess of 40 percent in 1982. The ongoing returns in both years add another seven percentage points to the stand alone returns.

TABLE 1.9

Expected Real Returns from Texas OCS Oil Reservoir Investments under 1972 and 1982 Perspectives

(dollar figures are in U.S. dollars)

	Prolific Reservoir		Modest Reservoir	
	1972	1982	1972	1982
Internal Real Rate of Return (%)				
A. Pre Tax	41.6	104.6	14.2	63.1
B. After Tax, Stand Alone	29.4	76.7	6.6	41.7
C. After Tax, Ongoing	38.2	88.3	13.4	49.0
Net Present Value @ 10% Discount Rate ($MM, 1982$)				
A. Pre Tax	53.5	351.8	5.8	162.7
B. After Tax, Stand Alone	26.5	162.7	-4.1	67.7
C. After Tax, Ongoing	34.2	165.6	3.5	71.1
PV Tax Take as % of PV Resources Generated*				
A. Pre Tax	n/a	n/a	n/a	n/a
B. After Tax, Stand Alone	50.4	53.7	173.4	58.3
C. After Tax, Ongoing	36.0	52.9	37.6	56.2

* PV Resources Generated = Present Value at 10 percent of Gross Revenue less Development Cost less Operating Cost.

n/a = not applicable

These results imply that the less well endowed offshore reservoirs, which under the 1972 Perspective were a dubious economic proposition, are now attractive under the 1982 Perspective — if found.

The 'if found' qualification to the results for Texas, both offshore and onshore, is important. There is no doubt that chances of exploration success are relatively low for onshore regions because these lands have been worked over to a much greater degree than elsewhere and 'depletion' affects therefore are prominent. The same comment applies, albeit to a lesser extent, to offshore prospects. So in large measure attractive returns in 1982 for successful prospects are necessary to offset the relatively low likelihood of discovery. The significant improvement in returns, 1982 over 1972 means this feature is implicitly recognized by a fiscal system which has become relatively more generous than onerous over time.

1.5 Conclusions

This chapter has reported on individual reservoir evaluations for three regions, distinguishing between reservoir size and oil and gas and recognizing two time Perspectives — 1972 and 1982.

The prospective returns shown in the tables of this chapter exclude exploration costs, since such costs are normally not reservoir specific. Land acquisition costs also have been excluded because they mainly represent a discretionary transfer of surplus economic rent from companies to governments.

Overall appraisal of the results presented must recognize that over the full investment 'cycle' — from discovery, development and extraction to exhaustion — exploration costs must be recovered to enable the industry to survive. Thus a portion of what may look like quite attractive returns earned at the development and production phase must be regarded as being set aside to defray exploration costs. Also, increasing returns may be absorbed in part by additional land acquisition costs.

We reiterate that the inclusion of results relating to the North Sea and Texas is not to provoke comparisons of returns among the various jurisdictions but rather to place the changes which occurred in Alberta from 1972 to 1982 in perspective.

Bearing these caveats in mind, the main conclusions which emerge are as follows.

In Alberta, changes in fiscal systems from 1972 to 1982 have served to absorb much of the additional economic rent that any 'prolific' oil discovery would have expected to enjoy, although net present values at a 10 percent discount rate did significantly increase. Such 'prolific' discoveries have remained elusive over the past decade.

The picture for more modest sized oil reservoirs is different. Returns are more attractive in 1982 compared with 1972, although the increment may have been partly offset by higher exploration costs. At any rate, the apparent improvement is directionally consistent with the need to ensure that taxes and royalties do not discourage development of lower quality oil reserves. However, few 'modest' sized oil reservoirs have been discovered since 1970, and the additional returns, given the incidence of levies on gross revenues, are likely insufficient to make the discovery and development of higher cost supplies attractive.

The impact on rates of return of allowing for recovery of average exploration costs is strong, but with little significant change in relative terms between 1972 and 1982.

In the case of the Alberta gas reservoirs, rates of return are inferior in 1982 compared with 1972. Any inferiority is more pronounced the smaller the reservoir, suggesting the tax system is not sufficiently sensitive to variations in gas reservoir 'quality'. Profitability is also seen as especially sensitive to any delays in the marketing of gas discovered.

Overall, with the exception of certain smaller oil reservoirs, the incentive to invest in Alberta oil and gas reservoirs in 1982 is either much the same or inferior to that in 1972, notwithstanding the substantial increases in real oil and gas prices over this period.

What of the United Kingdom sector of the North Sea? In the case of oil, prospective real returns on reservoir investment have shown little change between 1972 and 1982, with threshold returns on smaller reservoirs heavily dependent on the ability of companies to immediately write-off tax allowances against other income. The case of North Sea gas is rather different. Returns in 1972 were constrained by a pricing regime which rendered reservoir discovery and development unattractive. By 1982 prospective returns improved appreciably, mainly reflecting a more favourable market oriented pricing mechanism.

The situation in Texas, whether onshore or offshore, is quite at variance from that in the North Sea and Alberta in terms of profits retained from successful reservoir development and production. Overall, returns in 1982 are significantly higher than in 1972, especially for smaller sized reservoirs. Correspondingly, the proportion of returns absorbed by taxes has either been relatively stable or has declined. Thus, profitability at the reservoir development stage is more attractive in 1982 compared with 1972. However, the question of offsetting rises in exploration costs is especially pertinent in these areas because more mature levels of exploration suggest 'depletion' effects have significantly raised the level of exploration effort required to find new supplies.

In short, changes in fiscal regimes between 1972 and 1982 in the United States have been benign, in the North Sea they have been quite neutral and in Alberta they have tended to be adverse. We find the overall incentive to invest in oil and gas in Alberta has tended to deteriorate between 1972 and 1982, for North Sea oil it is much the same but for North Sea gas it has improved, and in the United States investment has become uniformly more attractive as long as exploration efforts yield success.

Footnotes

[1] The actual outcome of aggregate investment in the oil and gas production sector is dealt with in Chapter 2.

[2] Frontier exploration was only at initial stages in 1972 and thus prospective returns were not well established. Even in 1982 jurisdictional matters and other factors make prospective returns ambiguous.

[3] The Texas analysis was confined to oil.

[4] Results for the zero COR rating are shown in the Appendix Volume, Appendix A.

[5] Results for 0, 5, 10 and 15 percent discount rates are tablulated in the Appendix Volume, Appendix A.

[6] See Chapter 3.

[7] If unlimited supplies of financial capital were available at a fixed rate, this proviso would not be important. But capital markets do not perform in this way, and for good reason the petroleum industry has relied heavily on internally generated funds.

[8] But the analysis in the succeeding Chapters 3 and 4 suggests real 'hurdle' rates have increased.

[9] It is only an approximation because allowance has not been made for exploration costs.

[10] See Eglington and Uffelmann (1983, Tables A.6 and A.8). Note also the tax treatment of bonus bids differed between periods. In broad terms, in 1972 bonus bids could be expensed; in 1982 they were written off on a declining balance basis. The more lenient tax treatment in 1972 would tend to raise bonus bids, other things equal.

[11] Eglington and Uffelmann, op.cit.

[12] Note the royalty system for gas is not production- sensitive.

[13] For numerical details on these two features, see Appendix Volume, Appendix A, Table A.17 and A.18.

[14] Results for both cost cases are shown in the Appendix Volume, Appendix B.

[15] In 1983 further tax changes were announced, with the APRT schedule to be reduced in stages until abolition in 1986 and with relaxation in certain other provisions, including higher oil allowances and the elimination of royalties for certain fields.

[16] In the Appendix Volume, Appendix B, results are reported for another 1972 price perspective where investors anticipate relaxation of price controls.

[17] For world oil price expectations, see Section 1.2 above. Expectations about inflation are the same for gas as those for oil.

[18] See comparisons in the Appendix Volume, Appendix B, between the 1972 market price results and those for 1982.

[19] At a 10 percent discount rate.

Chapter 2

INDUSTRY PERFORMANCE: ACHIEVED RATES OF RETURN

Economic theory tells us that if the expected rate of return on new investments exceeds the firm's cost of capital or 'hurdle' rate of return investment will proceed up to the point at which the two measures equate: the familiar marginal equivalence condition. Thus incentives to invest are affected by the interaction of both changes in expected profitability and in the cost of capital.

Changes over time in expected profitability from individual oil and gas reservoirs were examined in the preceeding chapter. The next step, determination of marginal rates of return on aggregate new investments in the oil and gas production sector as a whole and analysis of how both they and the marginal cost of capital to that sector have changed is a difficult exercise. We can at least observe how existing investments in the oil and gas sector have performed in aggregate through time. It must be recognized, though, that achieved average rates of return provide only a partial indication of the strength of investment incentives. The important dimension of changes both in expectations and in interactions between rates of return on new investment and the cost of capital is excluded.

This chapter focusses on evidence derived from accounting information on the rates of return the oil and gas production sector has achieved at different periods of time, after adjustment for inflation. To afford a broader perspective, the analysis has also been undertaken for other industries. The objective is to determine how achieved rates of return in the oil and gas industry have performed — both absolutely and in relation to other industries. The results will provide additional information on the subject of changes in the climate for investment in Canada's oil and gas industry.

In what follows, first we discuss the accounting approach employed to develop estimates of achieved 'real' rates of return on capital, 1972 to 1980[1] for the four industry sectors reviewed:

- oil and gas production
- manufacturing
- mining
- utilities

We then list and discuss the results of these calculations.

2.1 Inflation Adjustments: Technique

Ostensibly, determining rates of return achieved by selected Canadian industries over the past decade would be a relatively simple procedure: add up all the after-tax profits recorded by companies in the given industry and divide the total by the aggregate value of the assets employed. However, this sort of straightforward arithmetic is bedevilled by the presence of substantial and varying rates of inflation. As mentioned before,[2] a 12 percent return on assets achieved in 1972, when annual inflation was running at a rate of around 4 percent, is not at all the same thing as 12 percent return achieved in 1982 when inflation was running at 10 percent.

To make proper comparisons over time we need to eliminate as best we can the impact of inflation by focussing on *real* rates of return achieved where, as before, the term 'real' refers to returns achieved after adjustment for the veil with which inflation shrouds accounting returns. However, the adjustments required to compensate for inflation are far from simple, and indeed the procedures employed, constrained as they are by data limitations, are still a matter of ongoing research.[3]

In broad terms, the adjustments we make for inflation are patterned on those employed in a recent Economic Council of Canada study.[4] The methodology used attempts to identify and remove any inflationary effects embodied in annual accounting rates of return. The overall intent is to restore profitability measures to what they would have been in the absence of inflation.

In more detail: during inflationary periods rate of return calculations based on conventional accounting practices suffer from serious deficiencies which distort a company's profit picture and therefore its ability to finance future investments. These deficiencies include

- basing depreciation on the historical acquisition cost of assets, thereby understating the cost of assets used
- valuing materials used in the production process at their original cost, which undervalues inventories used
- overstating profits because account is not taken of the increases in working capital required by a firm to maintain sufficient liquidity during inflation
- overstating the cost of borrowed funds to the extent interest expenses represent compensation to the lender forerosion in the value of outstanding debt, not a reduction inprofits
- understating the asset base because most items are denominated in book rather than market values.

The results discussed later attempt to adjust for each of these deficiencies to yield more realistic estimates of achieved rates of return than would traditional accounting practices. A full discussion of the techniques used is given in Appendix D, Appendix Volume. Here we highlight the nature and rationale of the main adjustments.

The adjustments all attempt to uphold the 'capital maintenance' concept of income, a concept suggesting income should be defined after setting aside sufficient allowances to preserve a firm's ability to operate. In other words, profit is viewed as the maximum amount available for distribution after ensuring a firm is as well off at the end of a period as at the beginning. In the absence of inflation, traditional accounting practices normally meet this criterion.

2.1.1 Depreciation and Depletion Adjustment

Inflation introduces a wedge between accounting profits and real profits and renders depreciation charges relating to historical cost — the normal accounting practice — inadequate. The 'capital maintenance' concept of income requires a company to accumulate sufficient funds for asset replacement, implying depreciation be treated as a function of replacement cost. Ideally, this adjustment entails estimating the total cost of replacing a company's assets and then applying the appropriate rate of depreciation to the total replacement cost asset value. An analogous treatment is required for depletion charges — charges relating to the use of a firm's non-renewable resources to adjust these expenses to the equivalent of replacement cost depletion.

2.1.2 Net Depreciable and Depletable Asset Adjustment

Net depreciable assets usually constitute the main component of the asset base on which rates of return are calculated. Traditionally they are calculated as the book value of gross depreciable assets less accumulated book depreciation. Normally, their value will be understated when inflation is prevalent. The appropriate adjustment requires expressing the net value of these assets in terms of replacement cost.A similar adjustment is required for net depletable assets.

2.1.3 Land Value Adjustment

Accounting rates of return are usually calculated with land valued at its historical (acquisition) cost. During inflationary periods, such values would normally be understated. To adjust for inflation, the book value of land is replaced by an estimate of market value.

2.1.4 Cost of Sales Adjustment for Inventories

Inflation distorts the cost of inventories since Canadian tax laws require matching current selling prices with costs reflecting earlier, lower prices — the FIFO (first in first out) methodology for valuing inventory charges. This treatment understates the cost of sales when inflation is prevalent and thereby overstates profit. The remedy adopted is to adjust the historical value of opening inventories by the annual change in general price levels, thereby reducing reported profits when prices are rising.

2.1.5 Debt Adjustment

Inflation raises interest rates and this 'inflation premium' can be viewed as representing compensation to the lender for erosion in the value of his capital. For the borrower nominal interest is recorded as a tax deductible operating expense; for the lender it is taxed as income. Consequently the borrower's profit is understated because what is tantamount to repayment of debt is deducted from income without any adjustment for his gain on outstanding debt, while the lender's profit is overstated because what is a capital repayment is treated as income. Accordingly an adjustment is made which attempts to eliminate the 'inflation premium' component of interest charges in defining net income.

2.1.6 Working Capital Adjustment

Working capital is normally defined as the difference between current assets — cash, short term investments, accounts receivable and the like — and current liabilities, typically consisting of accounts payable and short-term loans. Again the problem of recording appropriate values arises when inflation contracts real values. To offset inflation, working capital is adjusted by a price index, reducing attributed income by any decline in the real value of working capital during the year.

2.1.7 Adjustments for Company Investments In and Loans to Other Companies

These adjustments concern problems which arise from aggregating accounting statements of companies in an industry holding investments in and making loans to each other. For example, a company holding shares in another company in the same industry would report dividends received as income, but the company paying the dividends would not deduct them from its income — instead they would be charged to retained earnings. Hence in aggregating industry profits to avoid double counting, dividends should be subtracted from the income of the recipient. Correspondingly, the relevant share investments need to be deducted from assets employed. Analogous adjustments apply to inter-company loans made within the same industry.

2.2 Estimated Real Rates of Return on Equity and Total Capital Employed

The primary focus of this study is on a comparison of 1972 and 1982, but in examining realized rates of return we wished to avoid over emphasis on individual years which might be affected by unusualcircumstances. Accordingly, rate of return calculations were undertaken over the period, rather than for just two points in time. At the time of writing, the last year for which suitable aggregate accounting data for the oil and gas production sector were available was 1980.

Table 2.1 summarizes the results of the calculations relating to the rate of return on equity undertaken for the period 1972 to 1980 inclusive; the numbers are also plotted in Figures 2.1 and 2.2. Both nominal and real rates of return on equity after tax are shown. Corresponding rates of return relating to total capital are listed in Table 2.2.[5]

TABLE 2.1

Rates of Return on Equity, Selected Canadian Industries, 1972 — 1980
(%)

	Oil and Gas Production			Total Mining excluding Oil and Gas Wells	
	nominal	real*	real**	nominal	real
	(1)	(2)	(3)	(4)	(5)
1972	6.9	3.0	2.4	4.6	1.4
1973	10.7	6.8	5.4	18.6	10.7
1974	13.6	6.8	4.9	19.2	9.0
1975	19.7	9.2	6.4	13.0	5.3
1976	21.4	10.7	7.1	11.8	4.4
1977	23.0	11.9	8.3	13.2	4.3
1978	22.2	11.3	7.4	13.8	4.3
1979	30.1	17.6	12.4	26.8	12.3
1980	25.3	14.4	9.4	25.9	10.6

	Total Utilities***		Total Manufacturing	
	nominal	real	nominal	real
	(6)	(7)	(8)	(9)
1972	12.3	7.1	10.8	6.9
1973	13.0	9.5	15.6	8.6
1974	13.0	10.2	18.8	9.0
1975	13.3	6.3	13.9	5.7
1976	12.0	5.2	12.6	5.9
1977	12.2	4.5	12.4	3.9
1978	13.0	4.6	15.0	4.9
1979	15.1	6.8	18.8	6.6
1980	14.6	6.6	16.7	5.2

* Calculated using mining price indexes to estimate replacement cost.

** Calculated using oil and gas production sector cost index to estimate replacement cost.

*** Excluding Crown Corporations

TABLE 2.2

Rates of Return on Total Capital, Selected Canadian Industries, 1972 — 1980

(%)

	Oil and Gas Production			Total Mining excluding Oil and Gas Wells	
	nominal	real*	real**	nominal	real
	(1)	(2)	(3)	(4)	(5)
1972	6.4	2.5	1.9	4.2	0.6
1973	9.8	5.6	4.3	14.6	7.3
1974	12.4	5.1	3.6	15.3	5.5
1975	17.3	7.5	5.2	10.7	3.3
1976	18.2	8.6	5.6	9.7	2.7
1977	19.4	9.8	6.9	10.6	3.0
1978	18.2	9.1	5.9	10.7	2.9
1979	23.8	13.3	9.4	20.4	9.0
1980	19.7	10.2	6.6	20.3	7.9

	Total Utilities***		Total Manufacturing	
	nominal	real	nominal	real
	(6)	(7)	(8)	(9)
1972	8.7	4.3	9.3	5.6
1973	9.2	4.4	13.2	6.4
1974	9.4	3.5	15.8	6.0
1975	9.8	2.9	11.9	3.9
1976	9.4	2.8	10.8	4.3
1977	9.8	3.3	10.7	3.0
1978	10.5	3.6	12.9	4.0
1979	11.6	4.2	15.9	4.9
1980	11.2	3.9	14.2	3.6

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* Calculated using mining price indexes to estimate replacement cost.

** Calculated using oil and gas production sector cost index to estimate replacement cost.

*** Excluding Crown Corporations

The nominal rate of return on equity capital after tax, that is the rate of return reported before adjustments for inflation, is defined as

$$NEK_t = \frac{RP_t - DV_t - IT_t}{INV_t + WC_t + BK_t + BL_t - NCL_t} \tag{1}$$

where NEK_t = nominal after tax return on equity, year t
RP_t = reported net profit before income taxes, year t
DV_t = dividends earned, year t
IT_t = income taxes paid, year t
INV_t = inventories valued at FIFO, mid year t
WC_t = working capital, mid year t
BK_t = depreciation and depletion assets at net book value, mid year t
BL_t = land at book value, mid year t
NCL_t = net longer term liabilities, mid year t

Equity capital as it appears in the denominator of equation (1) is treated as net current assets less net longer term liabilities plus depreciated net book values (historical cost).

In light of the discussion on adjustments for inflation (see Section 2.1), the *real* after tax rate of return on equity capital is defined as

$$REK_t = \frac{RP_t - DV_t + BD_t - RD_t - CSADJ_t \pm WCA_t + GL_t - IT_t}{INV_t + WC_t + KR_t + RL_t - NCL_t} \tag{2}$$

where REK_t = real after tax return on equity, year t
RP_t = reported net profit before income taxes, year t
DV_t = dividends earned, year t
BD_t = book depreciation and depletion expense, year t
RD_t = replacement cost depreciation and depletion expense, year t
$CSADJ_t$ = cost-of-sales adjustment for inventories, year t
WCA_t = working capital adjustment, year t
GL_t = gain on net longer term liabilities, year t
IT_t = income taxes paid, year t
INV_t = inventories valued at FIFO, mid year t
WC_t = working capital, mid year t
RK_t = depreciable and depletable assets valued at net replacement cost, mid year t
RL_t = land at replacement cost, mid year t
NCL_t = net longer term liabilities, mid year t

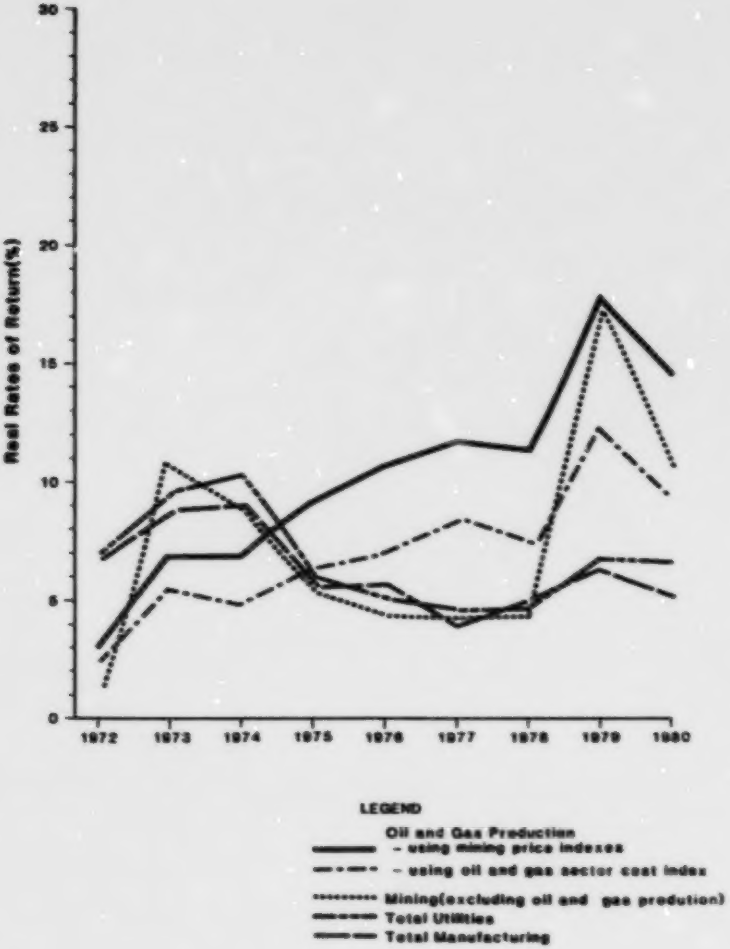

FIGURE 2.1: REAL RATES OF RETURN ON EQUITY,SELECTED INDUSTRIES

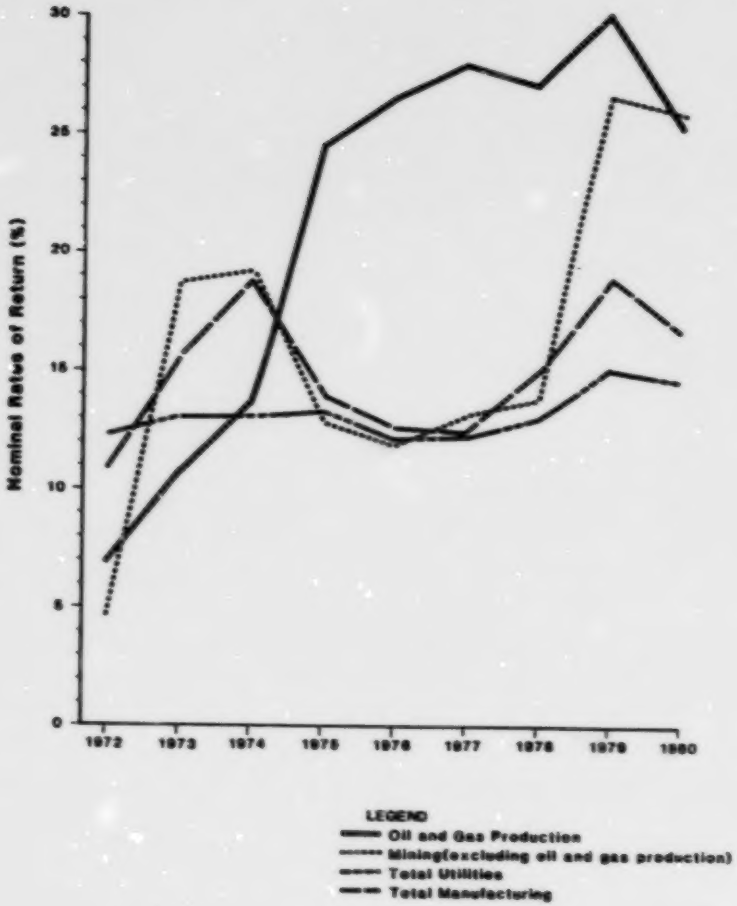

FIGURE 2.2: NOMINAL RATES OF RETURN ON EQUITY,SELECTED INDUSTRIES

Equity capital as defined in the denominator of expression (2) is net current assets less net longer term liabilities plus net depreciated values at replacement cost.

The expressions for nominal and real rates of return on total capital are analogous to (1) and (2); the main adjustments involve the adding back of long-term interest charges in the numerator and of net long-term debt to the denominator. (For details, see Appendix Volume, Appendix D).

2.2.1 Oil and Gas Production

The first two columns of Table 2.1 show equity rates of return for the oil and gas production sector. The third column recalculates real rates of return using a different price index, as discussed later. We see that the 1970s were characterized by increasing real rates of return on oil and gas equity capital. The sharp increases in 1973 and 1979 are especially noticeable. Full evaluation of these increases would require detailed analysis of individual company accounts, but the main reasons can be grasped from the behaviour of prices and output volumes. These suggest that the jump in earnings in 1973 was largely attributable to big increases in both production and prices for oil and gas, whereas the 1979 increase was due mainly to increased output, with little added impetus from prices.[6]

Another possible reason for apparent increasing real rates of return in the 1970s was that the industry had moved into a more mature phase when the positive cash flows generated by the heavy initial investments in the production sector up to, say, the mid 1960s had begun to be more prominent.[7]

The downturn in real rates of return in 1980 preceded the impact of new fiscal measures in the NEP, and, in comparison with 1979, seems mainly to reflect lower output. Although as mentioned above data are not available beyond 1980, information published by the Petroleum Monitoring Agency (PMA)[8] suggests that in 1981 oil and gas production sector after-tax profits fell in nominal terms by more than 40 percent over 1980 levels. This was mainly due to increased interest costs, higher operating costs and imposition of the Petroleum Gas Revenue Tax (PGRT). In 1982 there appears to have been some recovery: PMA statistics[9] indicate that upstream after-tax (nominal) profits rose by about 20 percent attributable in the main to higher wellhead prices and lower provincial royalties.

One source of bias in these oil and gas sector results is the reliance placed on the mining price index as a measure of replacement cost. The data for individual Alberta reservoirs in Chapter 1 (see Table 1.1) show substantial increases in costs at rates in excess of the mining price index. This suggests that an index specifically relating to replacement costs in the oil and gas production sector probably rose more rapidly than that for the mining sector as a whole.

Although cost indexes for the oil and gas production sector are not generally available, some recent (unpublished) data[10] suggest that during the 1970s equipment costs for oil and gas production rose in real terms at an average annual rate of some 5 percent, whereas the mining sector price index showed little appreciable real increase. The results of recalculating returns on equity using higher oil and gas replacement costs are shown in column (3) of Table 2.1. While they can only be regarded as an approximation, their direction is clear: there is a very significant reduction in achieved real rates of return.

2.2.2 Mining

Columns (4) and (5) in Table 2.1 relate to the mining industry, excluding the oil and gas production sector. The results are quite contrary to those for oil and gas. Real rates of return declined after peaking in 1973, only recovering in 1979 and 1980. This seems to mainly reflect depressed mineral prices during the mid to late 1970s. For example, Canadian copper and zinc prices rose significantly in real terms in 1973 and 1974 then declined each year to 1978, but with some revival in 1979. A similar pattern was shown for nickel and lead prices.[11] It is also apparent that returns in the mining sector are more erratic than those accruing from oil and gas production. This probably reflects the greater relative volatility of the commodity markets in which the mining industry operates.

2.2.3 Utilities

The returns on equity in the private utility sector (see columns (6) and (7), Table 2.1) are much more stable than those in mining and petroleum. This reflects both the impact of utility regulation and the inherently more stable markets served by utilities. One noteworthy feature is the decline in real rates of return until l979 or so, which may wellreflect lags in recognizing higher inflation rates in utility customer charges. This feature is borne out by the very stable *nominal* rates of return on equity recorded at least to 1978, notwithstanding increasingly severe inflation.

2.2.4 Manufacturing

Real rates of return on equity in the manufacturing sector are estimated to have been at modest levels after 1974, reaching a nadir of 3.9 percent in 1977; even after recovery in 1979 to 6.6 percent these real returns are still significantly below those achieved bymanufacturing in the early 1970s.[12]

2.2.5 Rates of Return on Total Capital

Table 2.2 parallels Table 2.1 but summarizes results relating to rates of return on total rather than equity capital. As would be expected given the normal effect of debt leverage, the rates of return on total capital are lower in all instances than those listed in Table 2.1. However, their general pattern of movement follows that for equity and thus much the same commentary as that on equity rates of return applies to returns on total capital.

2.3 Conclusions

A prominent feature of the estimated returns on equity shown in Table 2.1 is the increasing wedge represented by inflation as the 1970s progressed. And of course there is nothing surprising in this result: it simply parallels movements in the general rate of inflation in Canada over this period.

Inter-industry comparisons of rates of return based on accounting data are fraught with difficulty. Nevertheless, some broad comparative features do emerge.

We would expect real returns for the oil and gas production sector to be appreciably higher than those for utilities and total manufacturing, given the much higher risk to which this sector is exposed.[13] And this is indeed the case beyond the mid 1970s, but not in the early 1970s. Moreover, a portion of the higher equity returns achieved by the oil and gas production sector of late can be viewed as reflecting increasing debt financing relative to other industries.[14] Of itself, this would tend to raise rates of return on equity to compensate for the higher risk to which increasing fixed interest payments expose equity shareholders.[15]

Utility returns are remarkably stable in nominal terms, while in real terms increasingly stringent regulation after the mid 1970s seems to have reduced returns to modest levels approximatingmanufacturing returns. Yet given lesser risk, we would expect — other things equal — that utility returns would be lower than those in manufacturing.[16]

It is important to recognize that estimates of real rates of return are especially sensitive to the suitable definition of replacement costs. During the past decade the oil and gas industry has been subject to strong increases in real costs — costs rising at rates well in excess of inflation. When account is taken of such increases on the measurement of replacement costs, estimates of real rates of return achieved by the oil and gas industry erode quite dramatically.

Overall, real returns achieved by the oil and gas production sector improved in 1980 compared with 1972. However, to the extent actual performance mirrors expectations, the 1972 outlook was buoyant. In contrast, the trend in 1980 was one of decline, indicating an erosion in investment incentives. Results for the mining sector are more erratic but seem to indicate an improved performance in 1979 and 1980 compared with earlier in the decade. As would be expected, utility returns are much the same in 1980 as they were in 1972; manufacturing results were inferior in 1980 compared with 1972.

We caution again that these calculations afford only partial evidence of changes in investment incentives over time. Nevertheless, before the full impact of the NEP on upstream profits was felt, the oil and gas production sector performance had improved over the 1970s vis-a- vis manufacturing, but no clear pattern emerges in relation to mining and utilities.

Footnotes

[1] 1980 was the last year for which the relevant data were available when the analysis was undertaken (November 1983).

[2] See Chapter I.

[3] Accountants are making progress in providing information that better adjusts for biases which inflation introduces. However, as yet there are no generally accepted procedures applied to company accounting data.

[4] See Tarasofsky et al. (1981). In turn this work builds on the seminal analysis by Jenkins in this area; see Jenkins (1977).

[5] The sources of data used are listed in the Appendix Volume, Appendix D, Section D.4. Note that unlike firms in other industries petroleum companies do not follow one generally accepted accounting practice. However, aggregation of oil and gas company data compel us to treat all firms as using compatible accounting techniques.

[6] For information on output trends and average prices, see Canadian Petroleum Association, *Statistical Handbook*.

[7] Typically, the ratio of gross investment in depreciable and depletable assets to gross revenue was much lower in the 1970s than in the first half of the 1960s (see Statistics Canada Catalogue #61-207).

[8] Petroleum Monitoring Agency Canada, "Canadian Petroleum Industry Monitoring Survey 1981", Catalogue No. M27-22/1982E.

[9] PMA, op.cit., 1982, Catalogue No. M27-22/1982-2E.

[10] Source: Canadian Petroleum Association. For more details on the index, see Appendix Volume, Appendix D, Section D.4.

[11] Source: Energy Mines and Resources, Canada, Minerals Section. These prices were deflated by the GNE price index.

[12] The study by Tarasofsky et al. (1981, p.40) showed a similar pattern of results for manufacturing. Estimated real rates of return on equity were 1972, 6.8%; 1973, 9.2%; 1974, 8.5%; 1975, 5.2%; and 1976, 5.7%. The Department of Finance (1980) study exhibited similar trends.

[13] A characteristic confirmed by the risk analysis in Chapter 3 following.

[14] The debt proportion of the capital structure of theoil and gas production sector doubled between 1973 and 1980. In contrast, the debt burden assumed by mining, manufacturing and utilities over this interval was quite stable. (Source: Statistics Canada, Catalogue #61-207.)

[15] This feature has been dramatically illustrated by recent problems experienced by many oil and gas companies, of which Dome is the most visible example. Also, see Chapter 3 following.

[16] The analysis in the next chapter (Chapter 3) shows utilities enjoy much less risk than do manufacturing firms.

Chapter 3

THE COST OF EQUITY CAPITAL: MARKET EVIDENCE*

Important information on 'hurdle' rates of return and changes in risk is provided by investor perceptions. The question that can be posed is how have equity investors in Canada's oil and gas industry viewed changes over the interval 1972 to 1982, and what has happened to other industries?

This chapter seeks answers to this question by estimating the cost of equity capital to Canada's conventional oil and gas production sector and to other selected Canadian industry groups in 1972 compared with 1982. The estimates of the cost of capital rely on stock market information; the technique employed is the capital asset pricing model (CAPM). One feature of the analysis is a specific assessment of changes in risk.

In what follows below, we outline the nature of the CAPM approach used to develop estimates of the costs of equity capital, including measures of risk. We then apply the technique and discuss the results of our calculations for 1972 compared with 1982. Full details are provided in the Appendix Volume, Appendix E.

As mentioned beforehand,[1] the term 'hurdle rate' is frequently used to refer to the minimum rate of return a company would expect to earn on new investments. Thus, a firm's hurdle rate will correspond closely to its expected cost of equity capital. In this way, then, estimates of the cost of equity capital derived from capital market evidence will provide an objective measure of 'hurdle' rates of return,[2] at least in aggregate.

3.1 The Cost of Equity Capital and the CAPM

The cost of equity capital for a company can be thought of as the expected rate of return an investor could earn by investing in the shares of other companies of equivalent risk. In other words, it is the investor's opportunity cost of capital. If a company makes equity financed investments whose expected returns fall short of the cost of equity capital, investors will find they can obtain better returns elsewhere and will attempt to sell their shares. In so doing they will drive down the share price until at its new lower level the shares once again offer an expected rate of return commensurate with their risk. Thus the cost of equity capital is the minimum rate of return a company must obtain on its equity financed investment, assuming of course that the new investment has the same risk characteristics as the firm's current activities.

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*We acknowledge substantial advice and assistance from Dr. Michael Brennan of the University of British Columbia in undertaking the analysis discussed here.

The Capital Asset Pricing Model (CAPM) attempts to identify the relationship between the expected rate of return investors require on a security and its risk. By estimating the risk of an equity security, the expected rate of return required by investors may be inferred. And this will constitute the cost of equity capital for the company involved.

The fundamental concept underlying the CAPM is the distinction between 'diversifiable' or insurable risk and systematic risk. For the investor, company specific risks may be effectively eliminated through the law of large numbers by holding a portfolio of many securities in which individual or specific risk will tend to cancel out. For example, consider the risk that a particular oil well will be dry. For a company involved in several prospects, the risk of a given well to an individual investor may of itself be of little import to him in the same way that any individual claim is of little import to a life insurance company. Such risks are said to be diversifiable and consequently command little or no risk premium in the capital market.

An example of a non-diversifiable risk on the other hand would be fluctuations in the world price of oil, for a change in this price will likely affect the value of many assets an investor may hold. Obviously, investors tend to care more about systematic risk than they do about diversifiable risk, and it is not surprising to find that investors are willing to accept such systematic risk only if by so doing they can expect to earn on average a higher return than that available on riskless debt securities. The difference between this expected return and the 'risk free' return is called the 'risk premium'.

The *average* investor by definition would hold a portfolio which is a pro rata share of the market portfolio of all common stocks as approximated, for example, by the Toronto Stock Exchange (TSE) Composite Index. Consequently, the risks which are non-diversifiable or unique for him are those which contribute to the risk of the TSE Composite.

The contribution of a security to the risk of the market portfolio is usually measured by its Beta coefficient (B). The Beta coefficient can be thought of as the degree of fluctuation in the price of a stock divided by the corresponding degree of fluctuation in a suitable market index. If the return on a stock moves in perfect harmony with the market index, then the Beta of that stock is defined as unity. Thus, a security with a Beta of unity will move in concert with the TSE Composite and will command a risk premium equal to that on the Composite Market portfolio.

But if a security tends to go up (or down) in price by two percentages points when the TSE Composite advances (declines) by one percentage point it would have a Beta of (2/1) = 2.0. Such a security is relatively undesirable to an investor holding a well diversified portfolio like the TSE Composite for it accentuates the positive or negative changes in the value of his portfolio — his risk. Therefore, a high risk premium would be demanded for such a security. Finally, a security with a Beta of zero will tend to move completely independently of the Composite. If held in small quantities such a security will have a negligible effect on the risk of the investor's portfolio: its risk is entirely diversifiable and consequently it would command no risk premium.

Bearing these features in mind, in formal terms the capital asset pricing model (CAPM) to estimate a company's cost of equity capital can be written as

Cost of Equity Capital = Riskless interest rate plus Beta
of Equity times Market Risk Premium

or symbolically

$CE_j = R_F + B_j \times (R_M - R_F)$

where CE_j = cost of equity capital company j

RF_F = riskless interest rate

B_j = Beta of security j

RM_M = rate of return on the market portfolio as represented for example by the TSE Composite Index

The CAPM is a popular technique for estimating the cost of capital and has intuitive appeal. But it does raise certain statistical and theoretical issues which remain outstanding. The statistical problems focus on conducting thorough tests to ascertain the validity of the model; the theoretical concerns include whether Beta alone is sufficient to characterize systematic risk.[3]

3.2 Business and Financial Risk

A useful distinction can be made between business risk, the risk inherent in the basic operations of a company, and financial risk, the risk which relates to the proportion of a company's assets financed by equity. If a company were 100 percent equity financed, business and financial risk would be synonymous. But to the extent there are claims on company earnings which take priority over those enjoyed by equity shareholders, then the equity shareholder would be subject to additional risk. If the ratio of common equity to total capital falls, prior claims increase and the equity holder is exposed to extra financial risk. And in order to provide compensation for this increased risk the equity holder will require a higher rate of return on common equity. Thus the cost of equity capital — other things equal — will be higher.

Given this distinction between business and financial risk, we can think of the Beta applying to a company's overall assets — the asset Beta — as comprising the weighted average of the Betas of the firm's equity and debt, where the weights are the respective shares of debt and equity in the total market value of the firm.

If the firm's debt were regarded as riskless, then the corresponding equity Beta would simply be the company's asset Beta, the measure of business risk, adjusted upward by the ratio of the market value of the firm to the market value of its equity. To put it another way, an equity Beta will depend both on the Beta of the firm's assets and the firm's leverage as represented by the ratio of debt to equity. The higher this ratio, the higher the equity Beta.

Thus, in analyzing changes in the Betas of a firm's equity securities over time it is important to remember that these may reflect both changes in the underlying business risk measured by asset Betas and changes in the financial risk.

One remaining complication derives from the possibility that the tax deductibility of corporate interest payments provides a systematic benefit for firms which issue debt securities. Opinion on this is divided at present — there are strong arguments on both sides. Accordingly, the calculations of asset Betas (see Section 3.5) were undertaken on the basis of both crediting and not crediting tax benefits.

3.3 Equity Beta Estimates

The precise methodology employed to estimate equity Betas is described in the Appendix Volume, Appendix E, Section E.3. Suffice it to say here that various adjustments were made to account for periods when a stock may be only traded intermittently (the 'thin' trading problem) and for other problems.

3.3.1 Data

Since this study focusses on the producing sector of the petroleum industry, an initial list of forty companies was prepared which excluded integrated companies and other companies which had extensive interests beyond the production sector. Also, the companies had to be traded on the Toronto Stock Exchange (TSE) both in 1972 and 1982. Gaps in the data necessitated reducing the list to thirty-one companies.[4] Equity Betas were calculated for all these companies.[5] Calculation of asset Betas required information on a company's financial structure. Adequate consistent financial data were only available for seventeen companies for both 1972 and 1982.

Inter-industry comparisons of Betas were undertaken using Toronto Stock Exchange industry indices. The indices were for metals and minerals, oil and gas (including integrated oils), oil and gas producers, industrial manufactured products and utilities.

3.3.2 Results

The first four lines of Table 3.1 report estimated equity Betas for our oil and gas production sector sample (OGPSS) for 1972 and 1982 on four different bases.

TABLE 3.1

Industry Equity Beta Estimates

		1972	1982
Oil and Gas Production Sector Sample (OGPSS)	- unweighted, 31 companies	1.37	1.50
	- unweighted, 17 companies	1.36	1.38
	- equity weighted, 17 companies	1.32	1.26
	- weighted excluding Dome Petroleum	1.40	1.48
TSE Industry Indices:			
Oil and Gas		1.03	1.09
Integrated Oils		0.88	0.89
Oil and Gas Producers		1.22	1.21
Metals and Minerals		1.07	1.18
Utilities		0.57	0.50
Industrial Products		1.14	0.91
Composite		1.00	1.00

The weighted average Beta weights each company's Beta by the market value of its equity, and therefore is more representative of the larger production sector firms. This Beta value falls marginally from 1.32 in 1972 to 1.26 in 1982. The corresponding 'unweighted' Beta which gives all companies the same weight increases slightly between 1972 and 1982 from 1.36 to 1.38. Notably, Dome Petroleum accounted for about 64 percent of the equity value weights in the OGPSS. Given theextraordinary circumstances surrounding this company in 1982, little significance can be attached to its Beta estimate, affected as it was by threatened bankruptcy, implicit government guarantees, and the like. If this company were removed from the sample the weighted average industry Beta in 1982 increases from some 1.4 to 1.5.

The OGPSS Beta estimates all exceed those of the other indices by a wide margin, including the general Oil and Gas Index. The Beta of the average firm in OGPSS is 20-30 percent higher than that of the average firm in the TSE Oil and Gas Index. However, note that the Oil and Gas Index in 1982 also will be affected to some extent by Dome Petroleum, and more importantly includes integrated companies typically having much lower Betas (see Table 3.1).

Table 3.1 also shows utilities as enjoying significantly lesser risk than the TSE Composite; given regulation and assured rates of return, this is as expected. Industrial products — a surrogate for manufacturing — showed a decline in risk, 1982 over 1972, to levels below the industrial composite.

In summary, the equity Beta of the average firm in the OGPSS exceeds that of the average TSE company by a wide margin, and has increased somewhat from 1972 to 1982 both on an unweighted basis andon a weighted basis when Dome is excluded. The results confirm that the oil and gas production sector is perceived by investors as being both appreciably more risky than the average industry and more risky than other sectors of the petroleum industry.

3.4 Cost of Equity Capital

Recall from Section 3.1 above that the cost of equity capital was treated as the sum of the riskless interest rate plus the product of a company's equity Beta and the market risk premium.

Table 3.2 contains estimates of the cost of equity capital for the sample of 17 firms in 1972 and 1982.[6]

TABLE 3.2

Estimates of Cost of Equity Capital for Oil and Gas Production Sector Sample, 1972 and 1982

	1972	1982
	%	%
Nominal Terms		
Weighted	15.4	22.2
Unweighted	15.7	21.3
Real Terms		
Weighted	11.9	13.3
Unweighted	12.2	12.4

(The weighted results for 1982 exclude Dome Petroleum.)

Source: Appendix Volume, Appendix E, Table E.3.

In nominal terms the cost of equity capital appears to have increased by some six percentage points, or by not far short of one half of its earlier value. However, most of this is accounted for by higher inflation and, assuming that the average real return on Treasury bills will continue over the long run to be of the order of one-half percent per year, the real increase in the cost of equity since 1972 is of the order of one percentage point (weighted).[7] A pertinent question is whether this increment reflects increased business risk (including political risk), whether it reflects increased financial risk, or a combination of both.[8] Thus we now turn to the question of total asset Betas to measure changes in business risk.

3.5 Asset Beta Estimates

Section 3.2 of this chapter showed that the equity Beta of a company or industry depends upon both the relevant asset Beta — the Beta relating to all the company's assets, not just the equity component — and upon its leverage or capital structure. Specifically, the asset beta is the weighted average of equity and debt Betas.

There was a dramatic change in the leverage of our firm sample (OGPSS) between 1972 and 1982, as shown below

	1972	1982
Common Equity Ratio: 17 company sample	82 %	48 %
excluding Dome	82 %	65 %

where the common equity ratio is the ratio of common shares at market value divided by the sum of the common equity, preferred shares and debt. It is clear that even apart from Dome there was a significant increase in reliance on fixed income financing by firms in the oil and gas production sector between 1972 and 1982, which would have accounted for at least part of the increase in average equity Betas.

As explained in Section 3.2, the relation between asset Betas, equity Betas and leverage depends upon the assumptions made about the debt Beta and the value of the corporate tax deduction to shareholders relating to debt interest.

In Table 3.3 we have computed asset Betas for our firm sample for what we assumed to be the 'most likely' case: a 23 percent tax benefit,[9] a zero debt Beta in 1972 and a 0.2 debt Beta in 1982. The riskless debt assumption is probably appropriate for 1972 given the modest industry reliance on debt financing. By 1982 the situation had clearly changed with debt exposed to greater risk and the assumption of a Beta of 0.2, or an even higher level for the debt, is more reasonable.

TABLE 3.3

Estimated Asset Betas for Production Sector Sample

	1972	1982*
Asset Betas Assuming 23 % tax benefit Debt Beta, 1972 = 0; 1982 = 0.20	1.12	1.02

* Excludes Dome Petroleum

Source: Appendix Volume, Appendix E, Table E.4.

The result shown in Table 3.3 of a decline in 'Asset Betas' — a result sustained by almost every other combination of assumptions (see Appendix Volume, Appendix E, Table E.4) — suggests that the underlying business risk measured by asset Betas has if anything lessened between 1972 and 1982. In turn this implies that the increase in the industry equity Betas discussed earlier between 1972 and 1982 has not been due to an increase in the underlying overall asset risk, but rather reflects the increase in financial risk represented by leverage.

Accordingly, the estimates of a modestly higher real cost of equity capital in 1982 discussed above do not appear to reveal investor perceptions of the oil and gas production sector as subject to a higher degree of underlying business risk. Rather, the increase in the real cost of equity capital seems attributable to perceptions of the higher financial risk associated with a greater reliance on debt financing. The increase in the cost of equity capital also suggests 'hurdle' rates of return (in real terms) were higher in 1982 than 1972 but, again, the implication is that such a change would reflect a more risky financial structure rather than an increase in overall business risk. As we shall see in Chapter 4 following, this result is somewhat at variance with the perceptions of the people making the investment decisions.

Footnotes

[1] See Introduction.

[2] We abstract here from the impact of financial leverage on hurdle rates, and the more subjective aspects of hurdle rates which firms may impose. For more discussion, see Chapter 4.

[3] For criticism of the CAPM, for example see Roll and Ross (1983).

[4] For the company list, see Table E.1, Appendix E, Appendix Volume.

[5] Another approach would have been to use the index for production sector companies listed by the TSE, but we wanted to ensure the sample in each year related to the same companies, not a changing mix over time.

[6] For details, see Appendix Volume, Appendix E, Table E.3. The 17 companies are those for which we had adequate financial data.

[7] Recent real returns on Treasury bills are more in the order of 4 percent, an unusually high level. If such returns were to prevail over the longer run, the estimated cost of equity capital would be more in the range of 16 percent in real terms, compared with our estimate of 12 percent in 1982.

[8] For discussion of the distinction between business and financial risk, see section 3.2 above.

[9] This value is halfway between a zero tax benefit relating to the deductibility of debt interest and the maximum benefit of 46 percent.

Chapter 4

INDUSTRY PERCEPTIONS OF THE INVESTMENT CLIMATE

Chapter 1 referred to the importance of expectations in making investment decisions about assets with a long life. Chapter 2 examined industry performance as measured by achieved rates of return, and Chapter 3 looked at investors' perceptions as expressed in stock market behaviour. We now turn to perceptions of the investment climate by people involved in the oil and gas industry itself, perceptions that are crucial to the tempo of the industry. How do industry executives view prospective investment in the oil and gas production sector? And if the climate were viewed as adverse what policy measures does industry advocate to improve it? These are the issues addressed in this chapter.

The assessment of industry perceptions was based on several interviews with industry executives. The companies involved included

- five oil and gas companies of varying sizes and affiliations
- a bank
- an investment house.

The range of views expressed is discussed below in Section 4.1. Although the range is quite wide, a consensus does emerge on some issues, and this is summarized in Section 4.2. The discussion presumes that fostering investment in oil and gas production is desirable from the standpoint of public policy.

4.1 Industry Views

First we deal with the issue of hurdle rates, and then review matters relating to taxation, incentives and pricing.

4.1.1 Hurdle Rates

Conceptually, the 'hurdle' rate — a yardstick rate which projects must exceed to qualify for implementation — was given varying degrees of credence. Executives using hurdle rates did not normally focus on one specific number; a range was employed, typically reflecting variations in risk as a function of the nature of a project, its size and the like. Other executives did not find the hurdle rate a particularly meaningful tool. Financiers placed much more weight on the timing of cash flow than on the prospects for achieving or exceeding any hurdle rate of return.

There was a general perception that to the extent hurdle rates were relied upon, they had registered a definite change, 1982 compared with 1972. Circumstances in 1972 were seen as relatively stable: major upheavals in fiscal regimes had not been experienced, nor had prices shown abrupt changes. The view in 1982 was rather different. Firms became more aware of the fact that pricing and taxation agreements can be altered unilaterally by governments, especially those relating to large projects. Popular examples cited are the failure to honour pricing arrangements for Suncor's oil sands plant and the back-in provisions for PetroCanada, even for leases obtained before announcement of the NEP. Furthermore, by 1982 interest rates were more volatile and exploration risk was greater. All this suggests that, other things equal, hurdle rates were higher in real terms in 1982.

In light of the comment above about the ambiguity which surrounds hurdle rates, attempts to define figures lack precision. Nevertheless, it would seem that insofar as actual numbers can be specified, a range of 15 percent to 20 percent (after tax) in nominal terms would represent current notions.

4.1.2 Fiscal Terms

Most companies saw tax takes as being at inordinately high levels. With respect to structure, virtually all the companies interviewed expressed concern about the degree to which current fiscal arrangements embrace gross revenue taxes.[1] This feature is viewed as onerous, a situation accentuated by the fact that both royalties and the PGRT — the PGRT is in essence another form of royalty — are not deductible in defining income subject to federal income tax. Moreover, gross taxes were seen as a direct diversion of funds which could otherwise be invested in petroleum supply development.

Views were also expressed that the tax system had shifted to being more 'front end' loaded in recent years. This feature is confirmed by data on the distribution of shares of tax and royalty payments over time for the various hypothetical Alberta oil and gas reservoirs evaluated earlier.[2]

Financiers in Canada now see taxes as a major concern in assessing loans. Their review of a company's overall tax position has become more comprehensive, and lines of credit have been reduced.

The entire fiscal system is generally seen by all executives interviewed as far too complex.

4.1.3 Incentives and Grants

The present incentive and grants system is not viewed favourably. In particular the PIP grant system is believed to be inefficient, encouraging activity that might not otherwise be economically justifiable and involving a great deal of administrative complexity in the setting of COR levels and the like. Moreover, the system is believed to be inordinately costly.

The grant program also is seen as leading to too much implicit government direction in terms of where and when activity should take place.

As a means of inducing a greater degree of Canadian ownership, the PIP system is thought to be inappropriate. Other, more direct tax mechanisms would be preferred. In broad terms, discouraging foreign participation is not seen by those interviewed as a suitable objective: foreign funds will be required for the development of Canada's petroleum resources. Current Canadianization policies are believed to be too harsh on foreign companies.

4.1.4 Oil and Gas Pricing Policies

Not surprisingly, views on oil pricing were virtually unanimous: the vintage oil pricing system was rejected. One price should prevail, predicated on world oil prices. With decontrol, competition among refiners should set price differentials between crudes of varying quality.

Less cohesion was displayed by views on gas prices. More flexible pricing was certainly seen as desirable in the export market, and more freedom to negotiate was preferred for the domestic market. Decontrol in the case of gas was not viewed as a policy that could be quickly implemented. A two to three year transition period might be required before decontrol could be achieved.

4.2 A Consensus?

The general tenor of the industry views was one of quite profound dissatisfaction and even disillusionment with many policies affecting the industry. To this degree, then, the present general investment climate was seen as unfavourable, although it was pointed out that this did not detract from a relatively attractive outlook for certain kinds of activities, for example the search for new conventional oil supplies in Western Canada.

As indicated above, the main counts against the current structure of policies, fiscal terms and pricing affecting investment decisions related to stability, complexity, government intervention, the level and nature of tax takes, and selective incentives.

The quite dramatic and continuing changes in government policies in recent times are viewed as creating uncertainty. Projects are seen now as facing not only market risk but additional political risk to a degree not prevalent in the early 1970s.[3] Accordingly, a much more stable and predictable policy environment is highly desirable. Investment is also inhibited by the sheer complexity of present regulations and taxation measures which become more onerous to master the smaller the company.

Interventionist policies that favour investment in certain regions are believed to stimulate such activity, but not in a way that would lead to a healthy investment climate. This is because economic imperatives are distorted and the 'efficiency' of investment is lower.

The predominance of government takes based on gross revenues is seen as unfortunate. A tax system more oriented towards the taxing of profits than gross revenues was preferred. Apart from this structural issue, a reduction in the overall tax burden borne by the industry would both enhance profitability and provide additional funds for direct investment. Funds dispersed in various incentive schemes and grants were thought to better encourage investment over the long term if they were devoted to reducing overall taxes rather than being dispersed on a selective basis.

The overall view of decision makers that investment in the oil and gas production sector is more risky now than in the early 1970s contradicts the stock market evidence summarized in Chapter 3, which suggested that while the industry was exposed to more risk this mainly reflected greater reliance on debt and did not represent changes in underlying business risk. We cannot reconcile these views. Perhaps the capital market is interpreting the greater propensity of governments to intervene as a factor reducing the variability in returns. Alternatively, the technique we have employed to measure risk in the capital market may not comprehend changes in decision makers' perceptions.

Footnotes

[1] For numbers on the degree to which government tax flows obtained from the industry seem to have shifted over time towards a more direct relationship with gross rather than net revenues, see Appendix Volume, Appendix A, Table A.17.

[2] See Appendix Volume, Appendix A, Table A.18.

[3] In a published article, J. E. Feick of NOVA Corporation suggests that lack of confidence in future government action was a large factor in the cancellation of mineable oil sands projects (Feick (1983)).

Chapter 5

SOME CONCLUDING OBSERVATIONS

We indicated in Chapter 1 that if supply is sensitive to economic efficiency is served by allowing supply to respond to higher prices. Thus, as prices rise the industry should be able to 'climb up' the supply curve, bringing on supply increments of progressively higher cost as dictated by higher prices. In this context, the Alberta reservoir analysis in Chapter 1 offers little comfort. It could be argued that where oil and gas reservoirs of the same quality did not become more attractive to exploit between 1972 and 1982 — a period when prices rose dramatically — the fiscal system was acting as a well calibrated collector of what might seem to be 'windfall' profits. But the change towards greater reliance on gross revenue determined government levies and more front-end tax loading suggests the 1982 tax system was not well designed to serve economic efficiency.

Although the improved returns seen for modest sized oil reservoirs are directionally encouraging, higher exploration costs and the increased incidence of gross revenue related levies suggest that economic incentives to bring lower quality oil deposits on stream have not improved to the extent higher prices would dictate.

Changes in government policies towards the industry, then, seem to have constrained economic incentives to add new, higher cost supplies of oil and gas. In other words, the fiscal system has altered between 1972 and 1982 in a way that is less than socially optimal.

Mention has also been made of the strong increases recorded in real costs for the petroleum industry over the 1972 to 1982 interval, and especially in the 1970s. When the industry became less buoyant in the 1980s the legacy of these higher costs acted as a severe drag on profitability. In this vein, when circumstances became more adverse after introduction of the NEP, industry performance would have been more robust had costs been subjected to stricter discipline during the boom conditions of the 1970s. A part of these cost increases of course represented the normal impact of demand pressures on available supplies of labour and materials. But a portion might well have been avoided by more efficient purchasing mechanisms, cost controls and the like.

Another feature of mineral industries is the ambiguity that attaches to the proper definition of economic rent, where this rent is purportedly the 'true' surplus that can be extracted without affecting industry performance. Much of this ambiguity reflects the fact that what is a cost and what is a rent depends on the time horizon of the observer. In the short term, apparent 'windfall' profits reaped by rising prices may be absorbed easily over the long term by higher replacement costs if the industry is to 'maintain' itself in terms of adequacy of supply. Note that the concept of industry 'maintenance' is analogous to the definition of income used in the analysis in Chapter 2 of actual returns achieved by the industry, namely that income should be a residual after making sufficient provision to preserve a firm's ability to operate. And indeed we found in Chapter 2 that achieved industry returns were very sensitive to the way replacement costs were estimated. Thus, what may appear as rents in the short run may be absorbed by higher long run costs when, to offset resource depletion, industry ploughs back current profits in the search for new supplies.

In Chapter 4 we commented that we were unable to reconcile what might be regarded as the 'objective' market evidence on the cost of equity capital developed in Chapter 3 with 'subjective' evidence based on industry executives' views. The market evidence suggested that the increase in equity capital costs in 1982 compared with 1972 did not represent perceptions by investors of higher business risks, but rather the effect of additional financial risk brought about by greater reliance on debt. In Chapter 4 the 'subjective' assessments of industry executives identified a definite increase in business risk, related to the likelihood that governments would change the rules of the game and one way or another prevent industry from enjoying returns it regards as adequate. Such higher risks were reflected in higher 'hurdle' rates.

While, as we said, reconciliation is difficult, perhaps the increased role of government in manipulating prices and tax levers could be seen by the market as reducing uncertainty and protecting investors in some degree against downside risk. On the other hand, the ability to enjoy upside gains would likely be reduced. For example, given a lesser degree of sensitivity of fiscal levies to variations in profits, higher costs will reduce returns in a way in which governments would not share. In 1982, compared with 1972, the petroleum industry was undoubtedly treated by governments in a manner more akin to a regulated utility. And if market investors shared this perception, it could account for their viewing business risk as no greater — and even less — in 1982 than a decade earlier. Paradoxically, then, greater government involvement can be seen by capital markets as reducing risks. But dispersing risks by government controls is not socially desirable if they simultaneously reduce incentives to invest.

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APPENDIX VOLUME
THE OIL AND GAS INVESTMENT CLIMATE: CHANGES OVER A DECADE

APPENDICES TO CERI STUDY NO. 20

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INTRODUCTION

This volume consists of five appendices of supporting detail for the analysis in various chapters of the DataMetrics Limited study "The Oil and Gas Investment Climate: Changes Over a Decade," funded by the Canadian Energy Research Institute (CERI) and published as CERI Study No. 20.

Specifically, Appendices A, B and C provide additional information on the analysis of expected reservoir profitability for Alberta, the North Sea and the United States, respectively, discussed in Chapter 1 of Study No. 20. Appendix D corresponds to Chapter 2, providing more detail on the various adjustments made to accounting data in estimating real rates of return achieved by various industry sectors. Appendix E contains supplementary material on the behaviour of capital markets in the assessment of risk and the cost of capital described in Chapter 3 of Study No. 20

APPENDIX A

ALBERTA: RATES OF RETURN ON OIL AND GAS RESERVOIR INVESTMENTS

Appendix A

ALBERTA: RATES OF RETURN ON OIL AND GAS RESERVOIR INVESTMENTS

This appendix provides further details on the analysis of reservoir profitability in Alberta discussed in Chapter 1 of CERI study #20. Two types of hypothetical reservoirs were examined - termed 'Prolific' and 'Modest' - for both oil and gas deposits. The material below outlines the assumptions made about both the physical characteristics of the hypothetical reservoirs and the relevant economic parameters, distinguishing where necessary between the 1972 and 1982 Perspectives. The results of the evaluation of reservoir profitability are tabulated and discussed. We deal first with oil reservoirs (Section A.1), then gas reservoirs (Section A.2).

A.1 Analysis of Oil Reservoirs

A.1.1 Basic Data and Assumptions Employed

The reservoir analysis was confined to 20 years; none of the reservoirs were depleted within this period.

(a) Reservoir Configuration and Production

Total recoverable reserves for the Prolific oil reservoir were set at some 100 million barrels (16 $10^6 m^3$); those for the Modest reservoir were set at some 20 million barrels (3.2 $10^6 m^3$). To simplify comparisons, the acreage of both reserves was set at 8,000 acres (3,200 ha). The resulting reserve 'densities' - reserves divided by area - in the Prolific case approximate those for reservoirs such as Sturgeon Lake South D-3 and Snipe Lake BHL; the reserve density for the Modest reservoir would typify that in such fields as Clive D-3A and Carson Creek North BHLA.

The Prolific oil reservoir was characterized by a peak production rate of 175 b/d (28 m^3/d) per well; that for the Modest reservoir was 60 b/d (9.5 m^3/d) per well.

Table A.1 summarizes the oil reservoir reserves and production data.

TABLE A.1
RESERVES AND PRODUCTION DATA: HYPOTHETICAL OIL RESERVOIRS

	Prolific	Modest
Initial Reserves	100 MM bbls (16 $10^6 m^3$)	20 MM bbls (3.2 $10^6 m^3$)
Area	8,000 acres (3,200 ha)	8,000 acres (3,200 ha)
Peak Average Well Production Rate	175 b/d (27.8 m^3/d)	60 b/d (9.5 m^3/d)
Number of Wells	50	50
Peak Reservoir Production	8,100 b/d (1,294 m^3/d)	2,800 b/d (444 m^3/d)

Source: DataMetrics Limited's composite from several industry sources.

The production profile for each type of reservoir is the same, with each well producing the assigned peak production rate by the third year, then declining at 10 percent per year thereafter.[1] Each well is drilled and completed in one year. Each reservoir is developed by 50 wells, distributed over the first four years at 15, 15, 10 and 10 wells respectively. The Prolific reservoir is assumed to be deeper than the Modest reservoir.

The assumed physical features of the reservoirs do not of course change between the 1972 and 1982 Perspective analysis.

(b) Development and Operating Costs

The development and operating costs for oil reservoirs are listed in Table A.2. In terms of location, both the Prolific and Modest reservoirs were assumed to be in the general Plains region.

Drilling costs are primarily a function of well depth and the Prolific reservoir is assumed to be at a greater depth than the Modest one. The drilling cost values set were based on industry information. They are augmented by an allowance of 15 percent to cover the cost of anticipated dry development wells. Implicitly, this allows for 15 dry delineation wells per 100 productive development wells drilled.

TABLE A.2

OIL WELL CAPITAL AND OPERATING COSTS, 1972 AND 1982 PERSPECTIVES

	Prolific	Modest
1972 Perspective (M 1972 $ per well)		
drilling	110	98
dry hole allowance	16	15
completion	85	59
ancillary	30	30
annual operating	12	10
annual overhead	2	2
1982 Perspective (M 1982 $ per well)		
drilling	545	489
dry hole allowance	81	73
completion	360	250
ancillary	125	125
annual operating	47	38
annual overhead	6.5	6.5

Source: DataMetrics Limited's composite of several industry sources.

The 1972 data represent a range of development costs of $1,380 to $3,370 per peak daily barrel of oil production. The 1982 data represent a range from $6,350 to $15,600 development costs per peak daily barrel of oil production. Given the increase in the GNE price index of 2.6 times over this interval (see Table A.3), the numbers suggest a substantial increase in real costs has been experienced - in excess of seventy percent over the decade.

Annual operating costs, which are also partly a function of well depth, were based on industry information, and represent an increase of about 60 percent in real terms over the decade.

Development of the reservoirs is assumed to be one hundred percent equity financed.

(c) Inflation Index for Converting 1972 Dollars to 1982 Equivalent Dollars

The general price index employed to convert the 1972 Perspective results from 1972 dollars to 1982 dollars is shown in Table A.3.

TABLE A.3

GNE PRICE INDEX

1972	1.000	1978	1.740
1973	1.091	1979	1.918
1974	1.258	1980	2.130
1975	1.393	1981	2.346
1976	1.526	1982	2.596
1977	1.633		

Source: Statistics Canada, Canadian Statistical Review, Publication No. 11-003E, Section 1, December 1983.

(d) Oil Price Expectations

The question of future price trends is a key feature of the general investment outlook. And at any one point in time quite a wide range of price expectations can be entertained. We have attempted to represent these expectations by a concensus view.

For 1972, we assumed Alberta oil prices would be viewed as directly related to world prices, then and in the future. Transport charges to Edmonton were deducted from a representative world oil price projection. Gathering costs, escalated from initial year values by the expected inflation rates, were deducted to reach wellhead values. Based on projections made at that time (for example, see Stanford Research Institute (1972)), the 1972 representative average wellhead Alberta price of \$2.82 per barrel (\$17.75/m^3) was anticipated to rise in real terms at about 2 percent per year until it reached a plateau at some \$4.00 (\$1972) for 1986 and subsequent years.

The 1982 Alberta pricing regime distinguishes between various categories of oil, but in the context of new investments the relevant category is the new oil reference price (NORP). This is fundamentally predicated on world oil prices, so the relevant price expectations relate to prevailing 1982 views on world prices. We characterize these by a pattern that would see world oil prices falling slightly in real terms until the late 1980s, then gradually rising to a plateau in real terms by the mid 1990s. The initial Alberta price in 1982 was $42.72 per barrel (NORP oil); in 1995 and subsequently it reached $48.26 per barrel (1982 $).

(e) Inflation Expectations

For the 1972 Perspective, an annual expected inflation rate of 3 percent per annum was adopted. In 1982, expected inflation rates were much higher: 9 percent was assumed to be expected in 1983, declining to 6.5 percent over the long run.

(f) Fiscal Terms

The main features of the 1972 fiscal regime were royalties and depletion allowances. In 1972 oil royalties ranged between 8 and 16 percent of gross revenue, depending on the well productivity. In terms of the hypothetical reservoirs, the Modest case incurs oil royalties at the minimum rate; the royalty rate for the Prolific case starts at the maximum rate but declines throughout the project life. Royalties were deductible against income tax - both federal and provincial. In the early years of the 'planning' period starting in 1972, the depletion deduction was automatic at one third of resource revenue. Regulation issued in advance in the early 1970s scheduled an alteration to earned depletion[2] in 1977, although exploration and development expenses between 1972 and 1976 could be accumulated to earn post 1976 depletion. Although later altered, this was the depletion treatment anticipated in 1972.

Development expenses were eligible for a thirty percent capital cost allowance.

The 1982 tax structure contains quite different royalty regulations, non deductibility of royalties from income subject to federal tax, the decline of earned depletion eligibility, and the inception of both special taxes - the PGRT and the IORT - and incentives, the PIP grant system.

Several of the 1982 taxes depend on the classification of oil. As mentioned above, to be consistent with the new investment hypothesis the hypothetical reservoirs are treated as qualifying for the NORP throughout their life.

Resultant oil royalty rates for NORP oil vary from 35 percent in the early years of the Prolific reservoir project to 22 percent as the production declines. For the Modest reservoir the royalty rate declines from a peak of 28 percent to 7.6 percent as the production rate declines.

Remaining earned depletion allowances depend on the Canadian ownership content of the firm and so vary between the cases considered.

The incremental oil revenue tax (IORT) is not applicable to NORP oil. The petroleum and gas revenue tax (PGRT) is set at 16 percent throughout, as the short term tax holidays were not announced until later in 1982.

The petroleum incentive payment (PIP) from the Alberta government also depends on the Canadian ownership content. The grants reduce the effective amount of investment for the firm and also affect the taxes payable since eligible depreciation is reduced accordingly. The 1982 analysis was undertaken for both the zero and for the hundred percent Canadian ownership ratings (COR) to cover the range of outcomes.

A.1.2 Result of the Analysis

The evaluations were conducted on a fourfold basis:

- before taxes and royalties
- after royalty and PGRT, before income tax
- 'stand alone'
- 'ongoing'.

Each framework is described below.

The before tax and royalty results effectively show the net revenues available against which taxes and royalties could be applied. In other words, the before tax and royalty net present values (NPV) indicate the gross 'surplus' (economic rent) available at given discount rates. The present value calculations were undertaken for (real) discount rates which varied from 0 to 15 percent.

The 'stand alone' calculations represent returns to private industry, that is after deduction of all taxes and royalties. Moreover, as the name implies 'stand alone' means the reservoir is evaluated on a strictly individual basis without consideration of the impact of it on a company's overall tax position. In contrast, while the 'ongoing' evaluation is also after tax and royalty, it does take account of any immediate tax reductions or credits a company may enjoy if it has other sources of income against which to write off tax deductions as incurred.

(a) Gross Returns

Both the pre-tax and royalty and pre-tax after royalty results listed in Tables A.4 and A.5 respectively show very substantial increases in returns and net present values in 1982 compared with 1972. And this is as would be anticipated, given the substantial increases in real prices over this interval.

All the figures in these tables are expressed in 1982 Canadian dollars. The manipulations required to express the results in this form are as follows. The 1972 Perspective calculations are undertaken initially in expected nominal dollars, which involves application of the expected 1972 Perspective inflation rates discussed above (see A.1.1(e)). These projections are then deflated to 1972 dollars using the 1972 'vintage' expected rates of inflation, and rates of return and net present values in real terms are calculated. The 1972 dollar quantities are then translated into 1982 dollars by applying a factor of 2.6 (see Table A.3). The 1982 Perspective results are initially undertaken in nominal dollars and then deflated to 1982 dollars by employing the expected 1982 rates of inflation (see A.1.1(e) above).

TABLE A.4

REAL PRE-TAX AND ROYALTY RETURNS FROM INVESTING IN OIL RESERVOIRS UNDER 1972 AND 1982 PERSPECTIVES

(1982 $)

	Prolific Reservoir			Modest Reservoir		
	1972	1982		1972	1982	
		0% COR	100% COR		0% COR	100% COR
Real Net Present Value						
at 0%	235.2	1,170.5	1,221.8	48.6	364.4	370.2
at 5%	151.2	806.2	812.1	27.1	235.1	240.5
at 10%	102.1	568.5	574.1	14.5	160.0	165.1
at 15%	71.5	420.6	426.0	6.6	113.4	118.2
Internal Rate of Return (%)	68.9	202.5	229.6	22.0	77.7	88.5

TABLE A.5

REAL PRE-TAX BUT AFTER ROYALTY RETURNS FROM INVESTING IN OIL RESERVOIRS UNDER 1972 AND 1982 PERSPECTIVES

(1982 $)

	Prolific Reservoir			Modest Reservoir		
	1972	1982		1972	1982	
		0% COR	100% COR		0% COR	100% COR
Real Net Present Value						
at 0%	187.1	789.5	795.8	36.4	268.5	274.2
at 5%	118.6	513.2	519.1	18.5	166.1	171.4
at 10%	78.6	354.8	360.4	8.1	107.9	113.0
at 15%	53.8	257.4	262.7	1.7	72.6	77.4
Internal Rate of Return (%)	56.4	105.0	119.1	17.7	44.3	50.8

TABLE A.6

PROLIFIC OIL RESERVOIR
REAL 1982 VALUES, STAND ALONE BASIS
($ million - 1982 $)

	1972 Perspective	1982 Perspective	
		0 % COR	100 % COR
0% Discount Rate:			
Development Costs	31.5	55.1	48.9
Operating Costs	32.0	46.7	46.7
Gross Revenues	298.5	1,317.3	1,317.3
Corporation Tax (Fed & Prov)	76.1	414.7	416.7
Royalties	48.1	426.1	426.1
PGRT	-	152.1	152.1
Total Tax Take	124.2	1,492.8	994.8
Total Tax Take as % Res. Gen.* (%)	52.8	81.7	81.5
Net Present Value	111.0	222.8	227.1
5% Discount Rate:			
Development Costs	29.5	51.8	45.9
Operating Costs	19.7	28.8	28.8
Gross Revenues	200.3	886.8	886.8
Corporation Tax (Fed & Prov)	47.4	275.8	277.7
Royalties	32.6	293.0	293.0
PGRT	-	102.8	102.8
Total Tax Take	80.1	671.6	673.4
Total Tax Take as % Res. Gen.* (%)	52.9	83.3	82.9
Net Present Value	71.2	134.7	138.7

* Res. Gen. = Resources Generated = Present Value of Gross Revenue less Development Cost less Operating Cost.

TABLE A.6 (continued)

PROLIFIC OIL RESERVOIR
REAL 1982 VALUES, STAND ALONE BASIS
($ million - 1982 $)

	1972 Perspective	1982 Perspective	
		0 % COR	100 % COR
10% Discount Rate:			
Development Costs	27.9	49.0	43.4
Operating Costs	13.1	19.3	19.3
Gross Revenues	143.0	636.7	636.7
Corporation Tax (Fed & Prov)	31.3	195.6	197.3
Royalties	23.5	213.7	213.7
PGRT	-	74.0	74.0
Total Tax Take	54.7	483.3	485.0
Total Tax Take as % Res. Gen.*	(%) 53.6	85.0	84.5
Net Present Value	47.3	85.2	89.1
15% Discount Rate:			
Development Costs	26.5	46.5	41.2
Operating Costs	9.3	13.8	13.8
Gross Revenues	107.2	481.0	481.0
Corporation Tax (Fed & Prov)	21.6	145.9	147.5
Royalties	17.7	163.3	163.3
PGRT	-	56.0	56.0
Total Tax Take	39.3	365.2	366.8
Total Tax Take as % Res. Gen.*	(%) 54.9	86.8	86.1
Net Present Value	32.2	55.5	59.3
Internal Rate of Return (IRR)	(%) 47.0	44.3	49.8

* Res. Gen. = Resources Generated = Present Value of Gross Revenue less Development Cost less Operating Cost.

TABLE A.7

MODEST OIL RESERVOIR
REAL 1982 VALUES, STAND ALONE BASIS
($ million - 1982 $)

	1972 Perspective	1982 Perspective	
		0 % COR	100% COR
0% Discount Rate:			
Development Costs	26.2	47.1	41.3
Operating Costs	27.6	39.2	39.2
Gross Revenues	102.4	450.6	450.6
Corporation Tax (Fed & Prov)	14.2	126.2	128.8
Royalties	12.2	95.9	95.9
PGRT	-	49.4	49.4
Total Tax Take	26.4	271.5	274.2
Total Tax Take as % Res. Gen.*	(%) 54.2	74.5	74.1
Net Present Value	22.3	92.9	96.0
5% Discount Rate:			
Development Costs	24.7	44.2	38.8
Operating Costs	17.0	24.0	24.0
Gross Revenues	68.7	303.3	303.3
Corporation Tax (Fed & Prov)	6.3	82.4	84.6
Royalties	8.6	69.0	69.0
PGRT	-	33.5	33.5
Total Tax Take	16.8	184.9	187.2
Total Tax Take as % Res. Gen.*	(%) 62.1	78.7	77.8
Net Present Value	10.3	50.3	53.3

* Res. Gen. = Resources Generated = Present Value of Gross Revenue less Development Cost less Operating Cost.

TABLE A.7 (continued)

MODEST OIL RESERVOIR
REAL 1982 VALUES, STAND ALONE BASIS
($ million - 1982 $)

	1972 Perspective	1982 Perspective	
		0 % COR	100% COR
10% Discount Rate:			
Development Costs	23.3	41.8	36.7
Operating Costs	11.3	16.0	16.0
Gross Revenues	49.0	217.7	217.7
Corporation Tax (Fed & Prov)	5.1	57.3	59.1
Royalties	6.4	52.1	52.1
PGRT	-	24.2	24.2
Total Tax Take	11.4	133.5	135.5
Total Tax Take as % Res. Gen.*	(%) 79.2	83.4	82.1
Net Present Value	3.0	26.5	29.6
15% Discount Rate:			
Development Costs	22.1	39.7	34.9
Operating Costs	8.1	11.3	11.3
Gross Revenues	36.8	164.4	164.4
Corporation Tax (Fed & Prov)	3.2	41.8	43.4
Royalties	4.9	40.8	40.8
PGRT	-	18.3	18.4
Total Tax Take	8.1	100.9	102.6
Total Tax Take as % Res. Gen.*	(%) 122.7	88.9	86.8
Net Present Value	-1.5	12.6	15.6
Internal Rate of Return (IRR)	(%) 13.1	23.1	26.2

* Res. Gen. = Resources Generated = Present Value of Gross Revenue less Development Cost less Operating Cost.

(b) Post Tax, Stand Alone Basis

The post-tax stand alone positions are shown in Tables A.6 (Prolific reservoir) and A.7 (Modest reservoir). One noteworthy feature of both these results is the substantial increases in real costs, 1982 compared with 1972.[3] For example, real development costs in 1982 were not far off double what they were in 1972 to develop the identical reservoir with precisely the same configuration of facilities. This was supported by industry evidence. Had such costs not increased to this degree in real terms, the 1982 Perspective returns would have benefited accordingly.

Prolific Reservoir

Under the 1972 Perspective, the real internal rate of return (IRR) at 47 percent is attractive. Table A-6 also shows the tax take as a proportion of what we call the resources generated, where the latter are defined as gross revenues less investment costs less operating costs. As such it is a crude measure of economic rent, but only crude because the supply price of capital is not specifically deducted. Rather, this supply price is treated as synonymous with the particular discount rate applied. The tax take as a proportion of resources generated is generally just over 50 percent, staying much the same irrespective of the discount rate applied.

Under the 1982 Perspective, the real IRR is much the same as under the 1972 Perspective; and the IRR spread by COR rating is about 5 percentage points. The tax take becomes a very substantial 85 percent of resources generated, with an increasing trend as the discount rate increases, rising from 81 percent at zero discount rate to 86 percent at a 15 percent discount rate. This indicates that the taxation structure tends to front end load the time value of taxes. And of course the tax take is very much higher than in 1972; in effect the similarity in the IRR's between the two Perspectives indicates that changes to the tax and royalty regime implemented by 1982 have effectively absorbed any increment in economic rents accruing to a Prolific reservoir in 1982 compared with 1972, if we treat the 1972 IRR as a base. Net present values in 1982 at a 10 percent real discount rate exceed those in 1972 by some 80 percent.

Modest Reservoir

The pattern of results shown for the Modest reservoir in Table A.7 is somewhat different than that for the Prolific one. The 1972 perspective real IRR at 13 percent indicates a marginal return, while the tax take becomes very sensitive to the discount rate. When the discount rate is zero, the tax take as a proportion of resources generated is 54 percent - a bit higher than for the Prolific reservoir, but the proportion rises rapidly as the discount rate increases, reaching nearly 80 percent at a 10 percent discount rate. This demonstrates that the tax system in 1972 was not overly sensitive to reservoir 'quality', with the tax take being higher the poorer the reservoir, reducing a reservoir having a reasonable gross 'social' return of, in this case 22 percent (see Table A.4), to marginal levels.

The picture improves a lot under the 1982 Perspective, where although the tax take even at a zero discount rate is a lot higher in 1982 at 74 percent, the IRR is a respectable 23 to 26 percent, depending on the level of Canadian ownership. The general conclusion then is that in 1982 the economics of adding to petroleum supply by developing smaller, less well endowed reservoirs had improved compared with 1972. This is a socially desirable result, indicating that although taxes on resources generated have increased, nevertheless higher oil prices have made development investment more attractive at the margin. Put another way, to the extent higher (real) oil prices over time indicate scarcity and the consequent need to develop higher cost sources of supply, this would tend to translate between periods into higher returns for reservoirs of inferior quality.

(c) Post Tax, Ongoing Basis

Results for both the Prolific and Modest oil reservoirs on an 'ongoing' basis are shown in Table A.8.

TABLE A.8

RESULTS OF INVESTING IN OIL RESERVOIRS ON ONGOING OPERATIONS BASIS UNDER 1972 AND 1982 PERSPECTIVES

($ million - 1982)

	Prolific Reservoir			Modest Reservoir		
	1972	1982		1972	1982	
		0% COR	100% COR		0% COR	100% COR
Real Net Present Value						
at 0%	112.1	223.5	227.3	25.0	91.8	94.7
at 5%	72.4	135.5	139.3	13.4	49.9	53.0
at 10%	48.7	86.2	89.9	6.3	26.8	29.8
at 15%	33.7	56.6	60.1	-0.05	13.1	16.1
Taxes as % RG (zero discount rate)	52.3	81.6	81.4	48.6	74.8	74.4
PV Taxes as % PVRG* (10% discount rate)	52.3	84.8	84.4	56.5	83.3	82.0
Internal Rate of Return (%)	51.9	46.8	52.4	17.7	23.9	27.2

* PVRG = present value of resources generated.

For the Prolific reservoir, under the 1972 Perspective the ability to take advantage of tax deductions at the time they are generated increases the rate of return by about five percentage points, or about 10 percent, compared with the stand alone situation. The impact in 1982 is more modest at about two percentage points, reflecting the fact that although the overall tax take has increased, proportionately fewer excess tax deductions could be written off against other income in 1982 compared with the 1972 Perspective. Note that the much higher royalties and the PGRT in 1982 are all gross revenue taxes, and do not create surplus tax deductions.

In the case of the Modest reservoir, the benefit of being able to reduce taxes is especially noticeable under the 1972 Perspective, raising the stand alone IRR from modest levels of 13 percent to more generous levels of nearly 18 percent. In contrast, under the 1982 Perspective the increase in returns for an ongoing investment position compared with stand alone is marginal, amounting to only about one percentage point. Again this is because the tax savings for an ongoing project assumes much less significance under the 1982 Perspective.

A.2 Analysis of Gas Reservoirs

A.2.1 Basic Data and Assumptions Employed

As for oil, the gas reservoir analysis was confined to 20 years.

(a) Reservoir Configuration and Production

The Prolific reservoir was assumed to have reserves of some 180 BCF (5 $10^9 m^3$), while those for the Modest reservoir were set at 22 BCF (0.6 $10^9 m^3$). The areas of both reservoirs were set at 6,400 acres (2,600 ha.), sufficient to house 10 wells on 640 acre spacing. The Prolific reservoir is intended to characterize fields such as Jumping Pound or Limestone Rundle A. The Modest field represents less attractive prospects such as Provost Mannville Z, Alderson Accord White Specks or Haro Bluesky. Details are summarized in Table A.9.

TABLE A.9

RESERVES AND PRODUCTION DATA: HYPOTHETICAL GAS RESERVOIRS

	Prolific	Modest
Initial Estimated Reserves	180 BCF ($5\ 10^9 m^3$)	22 BCF ($0.6\ 10^9 m^3$)
Area	6,400 acres (2,600 ha.)	6,400 acres (2,600 ha.)
Peak Average Well Production	2,500 mcf/d ($70.5\ 10^3 m^3/d$)	300 mcf/d ($8.5\ 10^3 m^3/d$)
Number of Wells	10	10
Peak Reservoir Production	25 MMCF/d ($705\ 10^3 m^3/d$)	3 MMCF/d ($85\ 10^3 m^3/d$)

Source: DataMetrics Limited and industry sources.

(b) Development and Operating Costs

The development and operating costs adopted for gas reservoirs are listed in Table A.10. In terms of location, the Modest gas reservoir is assumed to be in the Plains area while the Prolific reservoir was assigned to the Foothills region at a depth double that for the modest sized reservoir. Note also that for the Foothills, well costs are much higher irrespective of depth.

TABLE A.10

GAS WELL CAPITAL AND OPERATING COSTS, 1972 AND 1982 PERSPECTIVES

	Prolific	Modest
1972 Perspective (M 1972 $ per well)		
drilling	380	60
dry hole allowance	57	9
completion	120	55
ancillary	60	60
annual operating	12	8.6
annual overhead	2	2
1982 Perspective (M 1982 $ per well)		
drilling	1500	255
dry hole allowance	225	38
completion	500	195
ancillary	250	250
annual operating	47	33
annual overhead	6.5	6.5

Source: DataMetrics Limited and industry sources.

As for oil, drilling and completion costs are treated as a function of well depth. Again, the allowance for dry development wells is 15 percent of drilling costs.

The 1972 data represent a range of development costs from $247 to $613 per peak daily MCF of gas production; the 1982 data range from $990 to $2,460 per peak daily MCF. In relation to general inflation (see Table A.3), this indicates a substantial increase in real costs.

(c) Inflation Index for Converting 1972 Dollars to 1982 Equivalent Dollars

The general inflation rate used is the same as that for oil (see Table A.3).

(d) Gas Price Expectations

In 1972 there was little distinction between domestic and export gas prices. The price forecast for natural gas was drawn from representative projections.[4] The 1972 gas price was 35¢/mcf. In real terms, the price was assumed to rise steadily for the first decade in response to tighter gas markets and price increases in competitive fuels. Thereafter the price of Alberta gas was assumed to register very little real growth as frontier supplies were expected to be on stream.

In 1982 a dual price regime had been instituted, one set of prices for domestic markets, another for export markets. Thus gas price expectations in this year reflected the anticipated mix of export and domestic prices, given the alignment of prices for gas serving domestic markets to the prices of crude oil set at lower than world market equivalence. Future prices were based on a volume weighted average of domestic and export prices, with declining export volume weights. The domestic price was based on the Alberta-Ottawa pricing agreements through 1986; thereafter it was increasingly related to expected world oil prices. Consequently, the domestic-export price differential was expected to diminish over time. On this basis, anticipated Alberta natural gas prices rose from $3.18 in 1982 to $4.90 in year 2001, representing a real annual average increase of 2.3 percent.

(e) Inflation Expectations

These were the same as discussed for oil (See A.1.1(e) beforehand).

(f) Fiscal Terms

The 1972 gas royalty rate was a flat 16 percent, with royalties deductible from taxable income. The depletion allowance was as described for oil. Drilling and completion costs were eligible for thirty percent capital cost allowance. Forty percent of the ancillary facilities relate to gathering systems and other surface facilities, which also attract a thirty percent capital cost allowance. The remaining sixty percent relates to compression and is eligible for a 20 percent capital cost allowance.

The gas projects in 1982 are subject to the same taxation changes as were described for oil, except that the royalty rate - a function of nominal prices - does not vary with production levels. The 1982 gas royalty rate was 33 percent of gross revenue and grows slightly throughout the twenty-year project life. The capital cost allowance rates are maintained as before with all development costs except for 60 percent of ancillary facilities being eligible for the thirty percent rate.

A.2.2 Results of the Analysis

As for oil reservoirs, the results are discussed on a 'gross' (i.e., pre-tax and royalty and pre-tax, after royalty), 'stand alone' and 'ongoing' basis.

(a) Gross Returns

The results of investing in gas reservoirs on a pre-tax and royalty basis and on a pre-tax but after royalty basis are shown in Tables A.11 and A.12. For both the Prolific and Modest reservoirs, the internal real rate of returns (IRR) pre-tax and royalty in 1982 are more than double those in 1972, a reflection of the real price increases recorded over this interval. The results pre-tax but after royalty show a significant change, with the spread between the 1982 and 1972 Perspectives narrowing, especially for the Prolific reservoir. On an after royalty basis, the Modest gas reservoir returns of 14.5 percent under the 1972 Perspective are at low levels.

(b) Post-Tax Returns, Stand Alone Basis

The after tax and royalty returns under the 1982 and 1972 Perspectives are shown for the two reservoir sizes in Tables A.13 and A.14 respectively.

TABLE A.11

REAL PRE-TAX AND ROYALTY RETURNS FROM INVESTING IN GAS RESERVOIRS UNDER 1972 AND 1982 PERSPECTIVES

(1982 $)

	Prolific Reservoir			Modest Reservoir		
	1972	1982		1972	1982	
		0% COR	100% COR		0% COR	100% COR
Real Net Present Value						
at 0%	145.9	489.3	492.9	10.6	48.4	49.0
at 5%	88.9	307.4	310.7	5.5	29.1	29.6
at 10%	57.0	205.9	209.0	2.6	18.3	18.9
at 15%	38.0	145.2	148.2	1.0	11.9	12.4
Internal Rate of Return (%)	61.4	135.9	157.7	20.8	49.4	53.6

TABLE A.12

REAL PRE-TAX BUT AFTER ROYALTY RETURNS FROM INVESTING IN GAS RESERVOIRS UNDER 1972 AND 1982 PERSPECTIVES

(1982 $)

	Prolific Reservoir			Modest Reservoir		
	1972	1982		1972	1982	
		0% COR	100% COR		0% COR	100% COR
Real Net Present Value						
at 0%	117.8	309.1	312.7	7.2	26.8	27.4
at 5%	70.9	191.8	195.1	3.3	15.2	15.8
at 10%	44.7	126.4	129.5	1.2	8.8	9.3
at 15%	29.1	87.4	90.4	-0.1	5.0	5.5
Internal Rate of Return (%)	51.0	73.6	85.6	14.5	24.0	26.3

Prolific Reservoir

The internal rates of return for the Prolific reservoir show a marked reduction in 1982 compared with the 1972 Perspective (see Table A.13). The spread is particularly marked for a company not enjoying PIP grants, amounting to some eight percentage points on the IRR. If a company enjoyed a 100 percent COR rating, its prospective rate of return in 1982 would be more comparable with that in 1972, about three percentage points less.

The reason for these results is primarily attributable to the very substantial increase in the tax burden in 1982. The tax take as a proportion of resources generated (at a 10 percent discount rate) is around 85 percent compared with 53 percent in 1972.

Modest Reservoir

The results for the Modest reservoir listed on Table A.14, show marginal returns, and again the 1982 Perspective deteriorates compared with that in 1972. Indeed, at a discount rate of 10 percent, the tax take in 1982 as a proportion of resources generated exceeds 100 percent. This means the tax take is sufficiently onerous as to ensure the reservoir does not make a real after tax rate of return greater than 10 percent. And a 10 percent real return is undoubtedly marginal for reservoir investment. These results also suggest the tax system is not well calibrated with variations in reservoir quality.[5] Recall that the gross social return for investing in the modest sized gas reservoir is quite handsome at around 50 percent (see Table A.11). To the extent the tax system inhibits the economic attraction of lower quality reservoirs, it would not be performing in a socially efficient manner.

(c) Post Tax Returns - Ongoing Basis

The results of the analysis corresponding to the position of investors already in a tax paying position - the 'ongoing' basis - are shown in Table A.15. In terms of the Prolific reservoir, the attributed tax savings do have a significant impact on the 1972 Perspective IRR, raising it by some five percentage points compared with the stand alone

TABLE A.13

PROLIFIC GAS RESERVOIR
REAL 1982 VALUES, STAND ALONE BASIS
($ million - 1982 $)

	1972 Perspective	1982 Perspective	
		0 % COR	100 % COR
0% Discount Rate:			
Development Costs	16.0	24.2	20.6
Operating Costs	6.4	9.7	9.7
Gross Revenues	168.4	523.2	523.2
Corporation Tax (Fed & Prov)	49.6	165.9	167.3
Royalties	28.1	180.2	180.2
PGRT	-	61.6	61.6
Total Tax Take	77.7	407.7	409.1
Total Tax Take as % Res. Gen.*	(%) 53.2	83.3	83.0
Net Present Value	68.3	81.5	83.7
5% Discount Rate:			
Development Costs	15.1	22.7	19.4
Operating Costs	4.0	6.0	6.0
Gross Revenues	107.9	336.1	336.1
Corporation Tax (Fed & Prov)	29.1	104.7	105.9
Royalties	18.0	115.6	115.6
PGRT	-	39.6	39.6
Total Tax Take	47.1	260.0	261.2
Total Tax Take as % Res. Gen.*	(%) 53.0	84.6	84.0
Net Present Value	41.7	47.4	49.6

* Res. Gen. = Resources Generated = Present Value of Gross Revenue less Development Cost less Operating Cost.

TABLE A.13 (continued)

PROLIFIC GAS RESERVOIR
REAL 1982 VALUES, STAND ALONE BASIS
($ million - 1982 $)

	1972 Perspective	1982 Perspective	
		0 % COR	100 % COR
10% Discount Rate:			
Development Costs	14.2	21.4	18.3
Operating Costs	2.6	4.0	4.0
Gross Revenues	73.9	231.3	231.3
Corporation Tax (Fed & Prov)	18.0	70.7	71.7
Royalties	12.3	79.5	79.5
PGRT	-	27.3	27.3
Total Tax Take	30.3	177.5	178.5
Total Tax Take as % Res. Gen.*	(%) 53.1	86.2	85.4
Net Present Value	26.8	28.4	30.5
15% Discount Rate:			
Development Costs	13.5	20.4	17.4
Operating Costs	1.9	2.8	2.8
Gross Revenues	53.4	168.4	168.4
Corporation Tax (Fed & Prov)	11.6	50.5	51.4
Royalties	8.9	57.8	57.8
PGRT	-	19.9	19.9
Total Tax Take	20.5	128.1	129.0
Total Tax Take as % Res. Gen.*	(%) 53.9	88.2	87.1
Net Present Value	17.5	17.1	19.1
Internal Rate of Return (IRR)	(%) 42.5	34.4	39.8

* Res. Gen. = Resources Generated = Present Value of Gross Revenue less Development Cost less Operating Cost.

TABLE A.14

MODEST GAS RESERVOIR
REAL 1982 VALUES, STAND ALONE BASIS
($ million - 1982 $)

	1972 Perspective	1982 Perspective	
		0 % COR	100 % COR
0% Discount Rate:			
Development Costs	4.8	7.4	6.8
Operating Costs	4.9	7.0	7.0
Gross Revenues	20.2	62.8	62.8
Corporation Tax (Fed & Prov)	3.0	16.1	16.3
Royalties	3.4	21.6	21.6
PGRT	-	6.7	6.7
Total Tax Take	6.4	44.4	44.6
Total Tax Take as % Res. Gen.*	(%) 61.0	91.8	91.1
Net Present Value	4.2	3.4	4.4
5% Discount Rate:			
Development Costs	4.5	6.9	6.4
Operating Costs	3.0	4.3	4.3
Gross Revenues	12.9	40.3	40.3
Corporation Tax (Fed & Prov)	1.7	9.9	10.1
Royalties	2.2	13.9	13.9
PGRT	-	4.3	4.3
Total Tax Take	3.9	28.1	28.3
Total Tax Take as % Res. Gen.*	(%) 72.2	96.5	95.3
Net Present Value	1.6	1.0	1.4

* Res. Gen. = Resources Generated = Present Value of Gross Revenue less Development Cost less Operating Cost.

TABLE A.14 (continued)

MODEST GAS RESERVOIR
REAL 1982 VALUES, STAND ALONE BASIS
($ million - 1982 $)

	1972 Perspective	1982 Perspective	
		0 % COR	100 % COR
10% Discount Rate:			
Development Costs	4.2	6.6	6.0
Operating Costs	2.0	2.9	2.9
Gross Revenues	8.9	27.8	27.8
Corporation Tax (Fed & Prov)	1.0	6.4	6.6
Royalties	1.5	9.5	9.5
PGRT	-	3.0	3.0
Total Tax Take	2.5	19.0	19.1
Total Tax Take as % Res. Gen.*	(%) 92.6	103.4	101.4
Net Present Value	0.2	-0.6	-0.3
15% Discount Rate:			
Development Costs	4.0	6.2	5.7
Operating Costs	1.4	2.0	2.0
Gross Revenues	6.4	20.2	20.2
Corporation Tax (Fed & Prov)	0.6	4.4	4.6
Royalties	1.1	6.9	6.9
PGRT	-	2.2	2.2
Total Tax Take	1.7	13.5	13.7
Total Tax Take as % Res. Gen.*	(%) 170.0	113.4	109.9
Net Present Value	- 0.7	-1.6	-1.2
Internal Rate of Return (IRR)	(%) 10.9	7.8	9.0

* Res. Gen. = Resources Generated = Present Value of Gross Revenue less Development Cost less Operating Cost.

TABLE A.15

RESULTS OF INVESTING IN GAS RESERVOIRS ON ONGOING OPERATIONS BASIS

($ million, 1982 values)

	Prolific Reservoir			Modest Reservoir		
	1972	1982		1972	1982	
		0% COR	100% COR		0% COR	100% COR
Real Net Present Value						
at 0%	68.3	81.7	83.9	4.7	4.1	4.4
at 5%	41.8	47.7	49.8	2.3	1.1	1.5
at 10%	26.7	28.8	30.8	0.9	-0.5	-0.1
at 15%	17.5	17.5	19.5	0.0	-1.4	-1.1
Taxes as % RG (zero discount rate)	40.7	83.3	83.0	55.4	91.6	91.0
PV Taxes as % PVRG* (10% discount rate)	33.4	87.9	86.8	67.5	102.6	108.8
Internal Rate of Return (%)	47.1	35.9	41.6	14.9	8.2	9.4

* PVRG = present value of resources generated.

case. But the impact of accelerated tax benefits for the 1982 Perspective is marginal, raising returns by only some one to two percentage points. It would seem that the excess tax write-offs available to be offset against other income are relatively smaller in the 1982 analysis.[6] Recall that the major increases in taxes relate to gross revenue, which do not create excess deductions.

A.3 Some Other Aspects

A.3.1 Exploration Costs

The calculated returns for both the oil and gas reservoir evaluation are at the reservoir investment phase and thus make no allowance for exploration costs. These of course can seldom be attributed to individual reservoirs, but nevertheless over the long run they need to be defrayed. In 1982 such exploration costs may well have increased on two accounts. First, a deterioration in 'prospectivity' given overall resource depletion effects may mean more effort had to be expended in 1982 to find equivalent amounts of oil and gas discovered in 1972. Second, the cost per unit of exploratory effort may well have risen in real terms, if the increasing real costs of reservoir investment afford any yardstick.

The allocation of exploration costs to specific reserves is the standard stumbling block inhibiting their inclusion in project evaluation. However, as the focus of this report is on changes over a decade, the pertinent question is the relative variation in whatever allowance is made for exploration costs. In the context of oil reservoirs, each approach considered indicated a rough doubling of real costs over the decade.

The first approach used aggregate annual data[7] relating exploration and geological costs to booked reserves. Application of these data to our assumed reservoir sizes yielded inordinately high exploration cost allowances. However, exploration costs per barrel of booked reserves are not likely to be constant over wide variations in reservoir size.

Average oil reservoir size was calculated for discoveries in the 1957 to 1964 period.[8] This indicated that both the prolific and modest reservoir sizes assumed were above average. If total exploration costs for the average reservoir size were used for both reservoirs, the implication is that the prolific and modest reservoirs are equally probable and that unit exploration costs vary inversely with reservoir size. However, larger reservoirs are harder to find than average sized reservoirs, and the inverse relationship was modified accordingly.

The second approach used to estimate an exploration allowance was to specify an exploration program of wildcat wells with a success ratio of 1 in 10 for a modest discovery and 1 in 40 for a prolific discovery, and assign costs to exploratory wells on the basis of both 1972 and 1982. Note that while the drilling component of exploration costs rose dramatically 1982 over 1972, the inclusion of geological and geophysical costs tempers the increase.

On the basis of estimates drawn from both these approaches, an allowance for total exploration costs for the Prolific reservoir was set at 10 million dollars (1972 $) in 1972 (26 million 1982 $) rising to 53 million dollars in 1982 (1982 $). For the Modest reservoir the total exploration cost allowance was 5 million dollars (1972 $) in 1972 ($13 million 1982 $) rising to 26 million dollars in 1982 (1982 $).

Table A-16 shows certain results after allowance for exploration costs. Their inclusion roughly halves the internal rate of returns shown earlier in this appendix relating to oil reservoirs. In 1982 the differences between the 100 percent and 0 percent COR cases are accentuated since the PIP grants on exploration are considerably higher than for development. The inclusion of exploration in the 1982 0 percent COR case caused a similar effect to its inclusion in 1972. The 100 percent COR case did not drop as far, given the exploration subsidy in the PIP grant system.

A.3.2 Adjustments for Gas Marketing Problems

No allowances have been made in the case of the natural gas under the 1982 Perspective for possible problems in marketing gas after a

TABLE A.16

EXPECTED REAL RETURNS FROM OIL RESERVOIR INVESTMENT IN ALBERTA UNDER 1972 AND 1982 PERSPECTIVE, WITH AN EXPLORATION ALLOWANCE

	Prolific Reservoir			Modest Reservoir		
	1972	1982		1972	1982	
		0% COR	100% COR		0% COR	100% COR
Internal Real Rate of Return (%)						
Pre Tax and Royalty	25.7	73.1	93.9	10.8	40.2	51.9
After Tax, Ongoing	28.4	25.7	32.2	10.4	16.0	20.3
Net Present Value @ 10% Discount Rate (MM 1982$)						
Pre Tax and Royalty	76.1	511.9	535.4	1.5	133.4	147.9
After Tax, Ongoing	37.0	61.9	72.6	0.5	15.7	22.8
PV Tax Take as % of PV Resources Generated*	51.4	87.9	86.4	66.7	88.2	84.6

* PV Resources Generated = Present Value at 10 percent of Gross Revenue less Exploration, Development, and Operating Cost.

reservoir has come on stream. We undertook some additional runs where, first, the gas production schedule was set back one year, and second where gas production in the first two years was reduced by 50 percent.

These results showed that the real rate of return after royalty and PGRT but before income tax drops from 73.6 percent to some 49 percent for the Prolific reservoir when production is postponed by one year. Alternatively, if the production were cut by 50 percent in the first two years the rate of return drops from 73.6 percent to about 51 percent real. For the Modest gas reservoir the one year delay in production causes a drop from 24.0 percent to 19 percent in the real rate of return (after royalty and PGRT, but pre-income tax). If the production were constrained by 50 percent for two years, the drop is from 24.0 percent to some 19 percent. What these results show is that a combination of deferrals in gas production and lower than expected levels of production would strongly influence expected returns.

A.3.3 Structural Taxation Aspects

Table A.17 shows data on the share of gross revenue related taxes in the total tax take, 1972 versus 1982. The term taxes as used here includes royalties.

In the case of a hypothetical Alberta 'prolific' oil reservoir, the relative burden of 'gross' taxes grew significantly in 1982 compared with 1972; for the modest sized oil reservoir it was only marginally higher. Much the same pattern was shown for gas.

Table A.18 summarizes the distribution of shares of tax and royalty payments over time for the various hypothetical Alberta oil and gas reservoirs. These results show a shift in the 1982 fiscal regime to payment of a greater share of total taxes and royalties in the initial years of operation.

TABLE A.17

SHARE OF GROSS REVENUE TAXES IN THE TOTAL TAX TAKE 1972 AND 1982 FISCAL REGIMES*

(percent)

		1972 Perspective	1982 Perspective
Oil:	Prolific Reservoir	43.0	59.3
	Modest Reservoir	56.1	56.3
Gas:	Prolific Reservoir	36.2	59.1
	Modest Reservoir	60.0	65.4

* Based on 'stand alone' results and evaluated at a 10 percent (real) discount rate; 1982 Perspective evaluated at 100 percent COR.

Source: Tables A.6, A.7, A.13 and A.14

TABLE A.18

PERCENTAGE DISTRIBUTION OF TAX AND ROYALTY PAYMENTS OVER TIME

(percent)

	Prolific Oil		Modest Oil		Prolific Gas		Modest Gas	
	1972	1982	1972	1982	1972	1982	1972	1982
Stand Alone Evaluation								
Year 1-5	21	34	22	35	13	23	12	19
Year 6-10	41	34	36	35	39	34	34	35
Year 11-15	26	22	30	20	33	28	38	30
Year 16-19	12	10	12	10	16	15	16	16
	100	100	100.	100	100	100	100	100
Ongoing Evaluation								
Year 1-5	21	34	10	35	12	23	-8	19
Year 6-10	38	34	51	35	40	34	50	35
Year 11-15	28	22	28	20	32	28	41	30
Year 16-19	13	10	11	10	16	15	17	16
	100	100	100	100	100	100	100	100

Note: Shares calculated in terms of 1982 $ and discounted to 1982 at 10 percent per year.

Footnotes

[1] This pattern is our own with some reference to National Energy Board profiles cited in a manuscript not yet published. An alternative profile is published in Energy Resources Conservation Board 81-B, "Estimates of Ultimate Potential and Forecasts of Attainable Productive Capacity of Alberta's Crude Oil and Equivalent", Supplementary Report on "Impact of the National Energy Program, The Federal Budget and Provincial Government Announcements on Supply Forecasts for 1980 to 1990 of Crude Oil and Equivalent, and Natural Gas", p.4-10. The choice of production profile, common to the two perspectives, does not greatly affect comparisons over the decade.

[2] The change in regulations stipulated that depletion allowances were limited to $1 for every $3 of eligible expenditure on exploration and development. The provision appears in the 1972 Tax Reform Act made public in late 1971.

[3] Also, see discussion above relating to Table A.2.

[4] See Stanford Research Institute (1972).

[5] A contributing factor may well be the fact that, unlike oil, gas royalties are not rate-of-production sensitive.

[6] For a greater impact of ongoing provisions on results, see North Sea results, Volume 2, Appendix B.

[7] See Eglington and Uffelmann (1983).

[8] G.C. Watkins (1971).

APPENDIX B

UNITED KINGDOM: RETURN ON OIL AND GAS RESERVOIR INVESTMENTS

Appendix B

UNITED KINGDOM: RETURN ON OIL AND GAS RESERVOIR INVESTMENTS

This appendix, which was prepared primarily by Alexander Kemp and David Rose, University of Aberdeen, Scotland, provides details on the analysis of North Sea oil and gas reservoir investments discussed in Chapter 1 of CERI Study #20. Two types of hypothetical oil and gas reservoirs are examined, termed 'Prolific' and 'Modest'; although the reservoirs are hypothetical, their assumed nature is aligned to actual experience.

The material below outlines in detail the assumptions made about both the characteristics of the reservoirs and their associated economic parameters - distinguishing between the 1972 and 1982 Perspectives where appropriate - and then tabulates the economic evaluations. Oil reservoirs are dealt with first (Section B.1), followed by natural gas (Section B.2). The Appendix also includes analysis of post-tax returns expressed in Sterling (Section B.3) and comments on the limitations of the analysis (Section B.4).

B.1 Analysis of Oil Fields

B.1.1 Basic Data and Assumptions Employed

(a) Recoverable Reserves and Production Profile

Total recoverable reserves are 500 million barrels (79 $10^6 m^3$) for the Prolific field and 100 million barrels (16 $10^6 m^3$) for the Modest field. Production starts five years after development investment is initiated. The production profile for the 500 million barrel field shows a three-year build up to a peak output of 180,000 b/d (29,000 m^3/d). This plateau output is maintained for three years. The decline rate is at 16 percent over a period of fifteen years. The terminal production rate is 10,000 b/d (1,590 m^3/d).

The 100 million barrel field has a two-year build up to peak production of 42,500 b/d (6,755 m^3/d).[1] This plateau output is maintained for two years. The decline rate is at 23 percent over a period of nine years. The terminal production rate is 4,000 b/d (635 m^3/d). The difference between the abandonment rates for the Prolific and Modest fields reflects higher fixed operating costs for the former.

(b) Development Costs

For the 1972 Perspective two sets of cost conditions have been incorporated in the analysis. In 1972, no oil production had been undertaken anywhere in physical conditions comparable with those found in the central and northern North Sea. Development expenditure in the first fields was just commencing, and there was a high degree of uncertainty regarding the eventual level of such costs. Thus, optimistic and pessimistic cost assumptions have been examined for both field sizes. Under the optimistic assumption total development costs for the Prolific field were taken to be £1,100 at 1972 prices per plateau daily barrel produced. This corresponds to $2,684 ($US) per plateau b/d at the then prevailing exchange rate. For the Modest field, developments costs of £1,300 at 1972 prices per plateau b/d or $3,172 ($US) at the then prevailing exchange rates are assumed. For the pessimistic cost case, development costs of £1,200 per plateau daily barrel ($2,928) are assumed for the Prolific field and £1,400 ($3,416) at 1972 prices for the Modest field.

For the 1982 Perspective, the Prolific field is assumed to have development costs of $20,000 at 1982 prices per plateau daily barrel, while the Modest field has total development costs of $30,000 per plateau daily barrel.

The basis for the costs employed was estimates published at the time of concern. A paper published by Shell in 1972 entitled "Oil and Gas Technology Offshore of the United Kingdom" (see summary in Petroleum Press Service, November 1972, pp.409-410) had development costs of £1,300 per plateau daily barrel at 1972 prices. The specific calculations referred to a very large field. The regular publications of Wood, MacKenzie, of Edinburgh, on the North Sea contained estimates of capital costs for the actual fields then under development. For several of the early fields the prospective costs were lower than those quoted in the Shell paper. Another source (D. I. MacKay and G.A. MacKay, "The Political Economy of North Sea Oil") quotes (p.73) average expected development costs for the first generation of fields of £1,400 - £1,500 per peak daily barrel at mid-1974 prices. At 1972 values these amount to £1,068 per peak daily barrel.[2] The figures for the 1982 perspective were obtained from a major oil company to reflect the range of possibilities on new fields. The Clyde field, whose development was announced in 1982, had expected development costs of $32,000 per peak daily barrel at 1982 prices.

The structure and phasing of developments costs for the two fields were determined in consultation with a major oil company operating in the North Sea. On the Prolific field, drilling costs are assumed to constitute 20 percent of total development costs, while on the Modest field a figure of 30 percent is assumed. The phasing of the costs is shown in Table B.1.

Although the reservoirs assumed to be developed in 1972 and 1982 are physically identical, the development profile for 1982 is longer, reflecting later and more realistic expectations about the speed of development.

(c) Operating Costs

Annual operating costs are assumed to be 5 percent of accumulated total development costs on the Prolific field and 6 percent of such costs on the Modest field.

(d) Production Start-up Date

For both field sizes the production start-up date is year 5 (with year 1 being the first year of capital expenditure) in the 1972 perspective and year 7 in the 1982 Perspective.

(e) U.K. Inflation Index for Converting 1972 Perspective Results to 1982 Equivalent Values

The general price index employed to convert the 1972 investment perspective results from 1972 sterling and dollars to real 1982 sterling and dollars is shown in Table B.2.

TABLE B.I

PHASING OF OIL FIELD DEVELOPMENT EXPENDITURES*

(real terms)

	1972 Perspective				1982 Perspective			
	Prolific Field		Modest Field		Prolific Field		Modest Field	
Time Period (year)	% of Total Drilling Costs	% of Other Capital Costs	% of Total Drilling Costs	% of Other Capital Costs	% of Total Drilling Costs	% of Other Capital Costs	% of Total Drilling Costs	% of Other Capital Costs
1		9		9		1		1
2		21		21		1		1
3		30		30		7		7
4	7	24	12	24		21		21
5	14	16	25	16		30		30
6	14		25		7	24	12	24
7	14		25		14	16	25	16
8	14		13		14		25	
9	14				14		25	
10	14				14		13	
11	9				14			
12					14			
13					9			

* Total development costs represent drilling plus other capital costs.

TABLE B.2

GNE PRICE INDEX

1972	1.000	1978	2.389
1973	1.160	1979	2.819
1974	1.441	1980	3.155
1975	1.678	1981	3.426
1976	1.945	1982	3.618
1977	2.107		

Source: United Kingdom Central Statistical Office

(f) Oil Price Expectations

For both the 1972 and 1982 Perspectives the oil price forecasts employed were aligned with the projections of world prices used in the Canadian analysis (see Appendix A).

(g) Inflation Expectations

For the 1972 Perspective, annual inflation rates of 6.5 percent are used for the 1972-74 period followed by annual rates of 5 percent to 1982. Thereafter a 3 percent annual rate is employed. Such rates are consistent with those employed by economic forecasters at the time. In relation to expected world oil prices, they imply approximately constant real oil prices in the period 1972-75, modestly rising ones for the rest of the 1970s and constant real prices in the 1980s.

For the 1982 Perspective, annual inflation rates of 6 percent are employed throughout the life of the fields. This implies falling real oil prices to 1984 followed by rising real prices.

(h) Exchange Rate Expectations

Under the 1972 Perspective, the average rate for that year of £ = US$2.44 was employed. A 7 percent devaluation in 1973 was assumed with the rate remaining constant thereafter. Under the 1982 Perspective an exchange rate of £ = US$1.78 was employed for 1982. It was assumed to fall to £ = US$1.60 in 1983, after which the rate remained constant. These rates are used to convert dollar denominated oil prices to sterling equivalent.

(i) Fiscal Terms

In 1972 royalties were levied at the rate of 12-1/2 percent of imputed wellhead values, with transport costs to the shore and initial treatment costs allowed as deductions from the landed or tax value of the oil. This can reduce the effective royalty rate to a considerable extent, especially on small fields. Effective rates of 10 percent were employed on the Prolific field and 8 percent of landed values on the Modest one. Corporation tax is levied at the rate of 52 percent with development costs being eligible for capital allowances of 100 percent first year basis. Royalties are deductible. In 1975, the Petroleum Revenue Tax (PRT) was introduced.[3]

Many changes were enacted from 1979 onwards. The post March 1982 budget rules were treated as the 1982 tax regime. They incorporate a rate of 75 percent for the PRT. Development costs plus an 'uplift' of 35 percent could be written off on a 100 percent first year basis until full payback of development costs is attained.[4] An annual oil allowance of 1/2 million tonnes was available for 10 years as a deduction. A 'safeguard' provision limited the amount of PRT payable by reducing the burden to zero when gross profits were less than 30 percent of accumulated field investment and by stipulating that the maximum amount on which the tax was payable in any one year was 80 percent of gross profits in excess of 30 percent of accumulated field investment. The safeguard provision lasted for a total period equal to 1.5 times the payback period. Royalty was deductible for PRT and PRT paid was deductible for corporation tax. In addition there was an advance PRT commencing in 1983 (APRT) payable annually for five years. This was at the rate of 20 percent of gross revenues after deducting an allowance equal to 1 million tonnes per year. APRT was creditable against normal PRT and if after five years the PRT liability was insufficient to absorb the APRT a cash refund would be made. APRT payable was allowed as a deduction in estimating field payback.

B.1.2 Results of the Analysis

The evaluations were conducted on a pre-tax and royalty basis, and in terms of taxable position both on a 'stand alone' basis - where a company would not have income against which to write off tax deductions as incurred - and on an 'on-going' basis, where the company enjoys immediate benefits from tax reductions.

In what follows the term tax refers to the combination of taxes and royalties.

(a) Pre-Tax Results

On a pre-tax basis the projects described above result in real internal rates of return for the Prolific field under the 1972 Perspective of 25.7 percent (optimistic cost) and 23.3 percent (pessimistic cost). The real net present values at 10 percent are $1,158 million (1982 $) and $1,022 million (1982 $). The Modest field under the 1972 Perspective has expected rates of return of 16.7 percent and 14 percent and net present values at 10 percent of $107 million and $65.8 million, according to the respective optimistic and pessimistic assumptions about costs. Under the 1982 Perspective the Prolific field has an expected return of 34.7 percent with net present value at 10 percent of $3,857.7 million (1982 $). The Modest field offers a 19.3 percent rate of return and net present value of $344 million (1982 $). Details are shown in Table B.3.

TABLE B.3
REAL PRE-TAX RETURNS FROM INVESTING IN OIL FIELDS
UNDER 1972 AND 1982 PERSPECTIVES
(U.S.$ million, 1982 values)

	Prolific Field			Modest Field		
	1972			1972		
	Optimistic Cost	Pessimistic Cost	1982	Optimistic Cost	Pessimistic Cost	1982
Real Net Present Value						
at 0%	3,840.7	3,599.3	14,191.5	455.2	391.5	1,508.5
at 5%	2,125.2	1,951.9	7,290.5	240.5	190.6	756.5
at 10%	1,158.0	1,022.8	3,857.7	106.6	65.8	344.3
at 15%	588.3	477.0	2,052.8	21.5	- 12.8	115.2
Internal Rate of Return (%)	25.7	23.3	34.7	16.7	14.0	19.3

Note that expression of results in the form of 1982 United States dollars required the following manipulations. The projected costs in £1972 were converted to £ nominal using the expected inflation rates referred to in B.1.1.(g) above. Gross revenues in United States nominal dollars were converted to sterling equivalent using the expected exchange rates (see B.1.1.(h) above). Tax calculations were done - as they must be - in nominal sterling. All these flows were then converted to United States (nominal) dollars at the expected exchange rate (see B.1.1.(h) above), then deflated to 1972 using the expected United Kingdom inflation rates (see B.1.1.(g) above). Finally, the numbers were converted to 1982 dollars by applying a factor of 3.62 (see Table B.2).

(b) Post-Tax, Stand Alone Basis

The post tax positions are shown in Tables B.4 (Prolific field) and B.5 (Modest field).

Prolific Field

For the Prolific field a comparison over the two periods depends very much of the discount rate employed. At zero (real) discount rate the investor is much better off under the 1982 Perspective: the net returns are well over twice as high even over the optimistic cost assumptions for 1972. At 5 percent real discount rates the investor is still noticeably better off under the 1982 Perspective. At higher discount rates, the differences in post-tax returns narrow considerably. The internal rates of return for both Perspectives are remarkably close, and constitute absolute levels which are probably acceptable to investors.

A primary causal factor in explaining these results is the increase in real capital costs over the period,[5] coupled with the fact that the time between initial expenditure and first receipt of income has increased. This means that when higher discount rates are employed the relative weight given to the cash flows at the beginning of a project increases. Thus when a zero real discount rate is employed the lifetime real gross revenues are around 4.6 times real development costs under the 'optimistic cost' 1972 Perspective. The corresponding calculation for the 1982 Perspective produces a figure of 7.1 times development

TABLE B.4

PROLIFIC OIL FIELD
REAL 1982 VALUES, STAND ALONE BASIS
(U.S.$ million)

	1972 Perspective		
	Optimistic Cost	Pessimistic Cost	1982 Perspective
0% Discount Rate:			
Development Costs	1,404.5	1,532.1	2,800.0
Operating Costs	1,226.9	1,261.9	2,866.1
Gross Revenues	6,469.8	6,385.0	19,857.6
Corporation Tax	1,685.6	1,578.7	3,630.3
Royalties	646.9	638.5	1,985.8
PRT	-	-	5,232.5
Total Tax Take	2,332.6	2,217.2	10,848.5
Total Tax Take as % Res. Gen.* (%)	60.8	61.7	76.4
Net Present Value	1,505.8	1,373.8	3,343.0
5% Discount Rate:			
Development Costs	1,217.3	1,328.0	2,204.4
Operating Costs	680.8	715.2	1,355.2
Gross Revenues	4,022.6	3,992.1	10,850.1
Corporation Tax	957.5	894.3	1,833.6
Royalties	402.3	399.2	1,085.0
PRT	-	-	2,873.2
Total Tax Take	1,359.8	1,293.5	5,791.8
Total Tax Take as % Res. Gen.* (%)	64.0	66.4	79.4
Net Present Value	764.7	655.4	1,498.7

* Res. Gen. = Resources Generated = Present Value of Gross Revenue less Development Cost less Operating Cost.

TABLE B.4 (continued)

PROLIFIC OIL FIELD
REAL 1982 VALUES, STAND ALONE BASIS
(U.S.$ million)

	1972 Perspective		
	Optimistic Cost	Pessimistic Cost	1982 Perspective
10% Discount Rate:			
Development Costs	1,072.8	1,170.3	1,773.3
Operating Costs	410.7	437.7	715.6
Gross Revenues	2,641.2	2,629.7	6,346.6
Corporation Tax	568.7	529.1	984.6
Royalties	264.1	263.0	634.7
PRT	-	-	1,668.9
Total Tax Take	(%) 832.9	792.1	3,288.2
Total Tax Take as % Res. Gen.*	71.9	77.5	85.2
Net Present Value	324.8	229.6	569.6
15% Discount Rate:			
Development Costs	958.3	1,045.4	1,452.6
Operating Costs	265.6	285.7	413.2
Gross Revenues	1,812.1	1,807.6	3,918.6
Corporation Tax	350.8	324.9	557.2
Royalties	181.2	180.8	391.9
PRT	-	-	1,014.3
Total Tax Take	532.0	505.7	1,963.4
Total Tax Take as % Res. Gen.*	(%) 90.5	106.1	95.1
Net Present Value	56.2	- 29.1	89.5
Internal Rate of Return (IRR)	(%) 16.4	14.3	16.4

* Res. Gen. = Resources Generated = Present Value of Gross Revenue less Development Cost less Operating Cost.

TABLE B.5

MODEST OIL FIELD
REAL 1982 VALUES, STAND ALONE BASIS
(U.S.$ million)

	1972 Perspective		
	Optimistic Cost	Pessimistic Cost	1982 Perspective
0% Discount Rate:			
Development Costs	503.9	542.6	1,275.0
Operating Costs	323.9	316.3	896.2
Gross Revenues	1,283.0	1,249.9	3,691.3
Corporation Tax	205.9	179.1	671.1
Royalties	102.6	100.0	295.3
PRT	-	-	63.0
Total Tax Take	308.6	279.1	1,029.4
Total Tax Take as % Res. Gen.*	(%) 67.8	71.4	67.7
Net Present Value	146.7	111.9	490.7
5% Discount Rate:			
Development Costs	439.3	473.1	1,009.6
Operating Costs	210.0	209.7	515.4
Gross Revenues	889.8	873.1	2,286.3
Corporation Tax	127.7	110.3	376.5
Royalties	71.2	69.9	182.9
PRT	-	-	53.6
Total Tax Take	198.9	180.2	613.0
Total Tax Take as % Res. Gen.*	(%) 82.7	94.7	80.5
Net Present Value	41.6	10.1	148.3

* Res. Gen. = Resources Generated = Present Value of Gross Revenue less Development Cost less Operating Cost.

TABLE B.5 (continued)

MODEST OIL FIELD
REAL 1982 VALUES, STAND ALONE BASIS
(U.S.$ million)

	1972 Perspective		
	Optimistic Cost	Pessimistic Cost	1982 Perspective
10% Discount Rate:			
Development Costs	387.9	417.7	813.6
Operating Costs	141.9	144.3	312.0
Gross Revenues	636.4	627.7	1,472.0
Corporation Tax	81.4	69.8	219.0
Royalties	50.9	50.2	117.8
PRT	-	-	43.4
Total Tax Take	132.3	120.0	380.1
Total Tax Take as % Res. Gen.*	(%) 124.2	182.8	109.7
Net Present Value	- 25.7	- 54.4	- 33.7
15% Discount Rate:			
Development Costs	346.3	373.0	666.1
Operating Costs	99.5	102.5	197.4
Gross Revenues	467.3	462.6	979.6
Corporation Tax	53.2	45.3	131.5
Royalties	37.4	37.0	78.4
PRT	-	-	34.2
Total Tax Take	90.6	82.3	244.1
Total Tax Take as % Res. Gen.*	(%) 421.4	(-)	210.2
Net Present Value	- 69.0	- 95.1	- 127.9
Internal Rate of Return (IRR)	(%) 7.8	5.6	8.8

* Res. Gen. = Resources Generated = Present Value of Gross Revenue less Development Cost less Operating Cost.

costs. When a 15 percent discount rate is employed the difference between the two Perspectives compresses. Discounted gross revenues are 1.89 times development costs under the 1972 Perspective and 2.70 times costs under the 1982 outlook (see Table B.4).

The change in the structure of the fiscal system over the period might have been expected to contribute to the impact that discount rates have on the results. Under the 1972 Perspective the royalty was the only 'off-top' payment. Under the 1982 system there is the Advance Petroleum Revenue Tax (APRT) as well. The two together constitute very large front-end payments on a 500 million barrel field. Thus when post-tax returns are discounted more heavily the more distant income (post-APRT) becomes comparatively less valuable. This explains why the tax take goes up from 76 percent in real undiscounted terms to 85 percent at a 10 percent real discount rate. However, it is also seen that the tax take under the 1972 Perspective goes up sharply as the discount rate increases. With a zero discount rate on the optimistic assumption the tax take is 61 percent and at 10 percent discount rate 72 percent. Thus the fiscal terms cannot adequately explain the changing relationship of post-tax returns at different discount rates.

What is especially important is that the real internal rate of return for the Prolific field is virtually the same irrespective of whether it were developed in 1982 or 1972, notwithstanding an increase of some six times in real oil prices over this interval. This suggests a combination of the tax system and additional real costs have effectively creamed off much of any additional economic rents created by the substantial rise in world oil prices over the interval examined.

Modest Field

The pattern of results for the Modest field is broadly similar to that for the Prolific field (see Tables B.4 and B.5). At low discount rates the investor is noticeably better off under the 1982 Perspective. As discount rates increase the returns come closer together. At a 15 percent real discount rate the investor is noticeably worse off under the 1982 Perspective. The internal rate of return is slightly higher under the 1982 Perspective, but under both Perspectives the field would probably be commercially unacceptable.

The reasons for the outcome are the same as those for the Prolific field. Real capital costs have increased over the period, as has the expected lapse of time between initial expenditure and first production. At zero discount rate real revenues are 2.5 times development costs under the 1972 Perspective. The corresponding figure for the 1982 Perspective is 2.9. While the ratio is still more favourable for the 1982 Perspective, the difference between them is much narrower than for the Prolific field.

The changing structure of the fiscal system over the period does not appear to be the main influence on the result. It is true that under the 1982 Perspective the tax take increases dramatically when viewed in discounted terms compared with undiscounted values. The APRT system clearly plays a role here, though the associated liability is relatively lower than on the large field because of the greater relative benefit from the 'flat' oil allowance.[6] However, under the 1972 system the tax take in discounted terms is seen to increase even more dramatically compared with the undiscounted values. The conclusion is that the changing real costs in relation to revenues over the period play the main role in causing the field to be unattractive.

It also seems that while the real after tax return has increased under the 1982 Perspective - suggesting the tax system has become more sensitive to less well endowed fields - nevertheless the economics of the Modest reservoir remain marginal, at least on a stand-alone basis.

(c) Post-Tax, Ongoing Basis

Frequently, investors in new oil and gas fields are already in a tax paying postion and there may be substantial advantages for such investors compared with new entrants. In the case of North Sea oil and gas there are worthwhile tax benefits under both the 1972 and 1982 Perspectives. Under the fiscal terms applicable in both periods a company in a tax-paying position would be allowed to set the capital allowances applicable to another field against existing income for corporation tax purposes. In 1972, any income from onshore activities or that from offshore gas exploitation would have been eligible for such offsetting arrangements. By 1982 many companies had achieved significant income from oil and gas exploitation in the North Sea and more investors were in a position to take advantage of this facility. Because capital allowances for most items of capital investment are available on a 100 percent first year basis the acceleration in tax relief is quite valuable when cash flows are considered in discounted terms.

In Table B.6 the returns to the investor already in a tax-paying position - the ongoing situation - are shown under 1972 and 1982 Perspectives for the respective oil fields. It is seen that post-tax discounted returns on both the Prolific and Modest fields are substantially improved over the 'stand alone' basis. The results also show that the extent to which the benefits of ongoing operations exceed those of operating on a project basis become greater the higher the discount rate. This follows because the value of the accelerated tax relief increases with the rate of discount employed. It is noticeable that the improvement in post tax returns is also relatively greater the lower the stand alone project returns and the higher the unit capital costs. Thus the increase in the rate of return on the Prolific field under the 1972 Optimistic cost case is from 16.4 percent (stand alone) to 27.5 percent. On the Modest field under the same case the rate of return increases from 7.8 percent to 17.5 percent. The latter has both lower reserves and higher unit costs. The change in tax takes mirrors these post-tax results. Thus overall tax takes discounted at 10 percent fall from 72 percent on the Prolific field and 124 percent on the Modest field under the 1972 scenario to 53 percent and 54 percent respectively under the same case on an ongoing basis.

TABLE B.6

RESULTS OF INVESTING IN OIL FIELDS ON ONGOING OPERATIONS BASIS (U.S.$ million, 1982 values)

	Prolific Field			Modest Field		
	1972			1972		
	Optimistic Cost	Pessimistic Cost	1982	Optimistic Cost	Pessimistic Cost	1982
Real NPV						
at 0%	1,615.6	1,497.3	3,582.8	184.8	154.2	602.9
at 5%	942.1	854.3	1,828.8	103.2	78.2	301.1
at 10%	541.8	472.0	931.3	49.4	28.4	132.2
at 15%	295.1	236.9	452.1	13.5	- 4.5	37.1
Taxes as % RG (zero discount rate)	57.9	58.3	74.8	59.4	60.5	60.3
PV Taxes as % PVRG (10% discount rate)	53.2	53.8	75.9	53.7	56.7	61.8
IRR (%)	27.5	24.5	27.0	17.5	14.2	18.1

PVRG = Present Value of Resources Generated

Following the logic of this argument, the fields under the Pessimistic cost case for the 1972 Perspective exhibit still greater improvements in their post-tax returns on an ongoing basis compared with stand alone. On the Prolific field the rate of return increases from 14.3 percent to 24.5 percent, while for the Modest field it changes from 5.6 percent to 14.2 percent. The tax takes in discounted terms (10 percent rate) fall from 78 percent on a stand alone basis to 54 percent on an ongoing basis for the Prolific field, and from 120 percent to 57 percent for the Modest field.

Under the 1982 Perspective both projects also exhibit a marked increase in returns to investors when exploited on an ongoing basis. The Prolific field shows a return of 27 percent compared with 16 percent on a stand alone basis and the Modest one a return of 18 percent compared with 9 percent. It is interesting to find that the relative improvement in rates of return under the 1982 Perspective is very similar to that achieved under the 1972 Perspective. The result is that the relationship between the investment perspectives has not changed to a perceptible degree when the analysis is undertaken on an on-going basis. Thus the net present values at low discount rates under the 1982 Perspective greatly exceed those under the 1972 Perspective, but as the discount rate is increased the net present values come closer together. At a 15 percent real discount rate the Prolific field is still more attractive under the 1982 Perspective compared with the Optimistic cost 1972 Perspective, but the internal rates of return are very close.

The Modest field is slightly more attractive under the 1982 Perspective than the Optimistic cost one under the 1972 Perspective but the rates of return are quite close. The higher real capital costs under the 1982 Perspective produce this effect. The tax system plays a part as well. Thus under the 1972 Perspective for the Prolific field the tax take (ongoing) goes down from 58 percent in undiscounted terms, to 53 percent in discounted terms at 10 percent. Under the 1982 system the tax take for the Prolific field goes up slightly from 75 percent to 76 percent. On the Modest field the take (ongoing) goes down from 59 percent in undiscounted terms to 54 percent in discounted terms (at 10 percent) while under the 1982 Perspective it goes up slightly from 60 percent to 62 percent. The existence of the APRT involving front-end loaded tax payments plays a main role here. This tax did not exist in the 1972 Perspective.

Overall, the availability of other income against which to claim tax allowances can play a key role in luring investment. Especially for inferior reservoirs it may make the difference between whether exploitation is commercially worthwhile or not.

B.2 Analysis of Gas Reservoirs

The pattern of the discussion here parallels that for the oil fields in Section B.1 above.

B.2.1 Basic Data and Assumptions Employed

(a) Recoverable Reserves and Production Profile

Total recoverable reserves are 3 trillion cubic feet (tcf) (85 $10^{12}m^3$) for the Prolific field and 0.75 tcf (21 $10^{12}m^3$) for the Modest field. The production profiles for both fields assume a two-year build up to plateau output of around 660 MMCFD (19 10^9m^3) on the Prolific field and 165 MMCFD (5 10^9m^3) on the Modest field. Plateau output continues for eight years for both fields. The annual plateau output is around 8 percent of recoverable reserves; the decline rate is 20 percent per year. Final production rates are around 70 MMCFD (2 10^9m^3) on the Prolific field and 18 MMCFD (0.5 10^9m^3) on the Modest one.

(b) Development Costs

The levels of development costs employed for both the 1972 and 1982 Perspectives were set with the aid of a major oil company with long experience in gas exploitation in the southern sector of the North Sea. The hypothetical fields chosen are both considered as representative in terms of costs of the southern North Sea sector. This is the sector which attracted investment in the late 1960s and early 1970s, an interest that has recently revived. A Modest field of 0.75 tcf could cost anything from $300 million to $600 million to develop in 1982 prices for the Perspective of that year. These figures include intangible drilling costs, pipelines (of length applicable to the southern sector), platforms and facilities, producing wells, equipment and compression. The corresponding range of figures for the Prolific field is $1.2 - $2.4 billion at 1982 prices. Economies of scale are generally not as great in the southern sector as in other producing areas. For purposes of the present exercise, the overall development costs of the Prolific field were taken as $1.4 billion at 1982 prices and for the Modest field, $450 million. The Prolific field thus has noticeably lower unit costs than the Modest one. This gives a range of operating conditions well inside the bounds of possibilities under 1982 circumstances. For calculating the 1972 Perspective, the cost escalations that have taken place over the 10 year period were fully taken into account. The resultant total development cost figure for the Prolific field was $271 million (at 1972 prices) and $87 million for the Modest field; the corresponding figures in 1982 dollars are $979 and $314 respectively.

The phasing of total development costs assumed is 20 percent in year 1, 30 percent in year 2, 30 percent in year 3, 10 percent in year 4 and 10 percent in year 5; no distinction is made between the 1972 and 1982 Perspectives. All these figures are in real terms.

(c) Operating Costs

Annual operating costs are assumed to be 5 percent of accumulated development costs for the Prolific field and 6 percent of such costs for the Modest field.

(d) Production Start-up Date

For both fields the production start-up date is year 4: year 1 is the first year of capital expenditure.

(e) Inflation Rates for Converting 1972 Perspective Results to 1982 Equivalent Values

The general price index employed to convert the 1972 investment perspective results from 1972 sterling to real 1982 sterling is the same as that used for the analysis of the oil fields (see Table B.2).

(f) Gas Price Expectations

In the United Kingdom the British Gas Corporation (BGC) has acted as a monopoly buyer of gas from the producers in the North Sea. In contract negotiations in the 1960s and 1970s the BGC endeavoured to fix a price which would given the producer only a "fair" rate of return. The intention was to extract any potential economic rents through the price offered to the concessionaire. The bargaining process under this quasi-regulated return system plus the fact that expected unit costs and load factors varied considerably from field to field led to a non-uniformity in beachhead (i.e., landed) prices. A representative price for a new field in 1972 would have been around 1.5 pence per therm.[7] The Viking field which came on stream then had such a price. In the early contracts gas price escalation formulae were incorporated giving some protection for inflation of costs. However, there was generally by no means full cover; 25 to 35 percent protection was common in the contracts signed in the later 1960s. Hardship clauses were incorporated in the contracts which gave rise to the possibility of further compensation in the form of higher gas prices.

For a price controlled situation with BGC as the monopoly buyer a 1972 price of 1.5 pence per therm has been adopted with an escalation rate averaging 60 percent of the expected rate of inflation (see B.1.1.(g) for expected inflation). This takes account of "extra" compensation awarded as a result of hardship claims.

The first market related contract in the North Sea related to the sale of gas from the Ekofisk field in the Norwegian sector to West Germany. A price of 2.1 pence per therm in 1973 was agreed. This price was indexed in relation to the prices of competitive fuels in West Germany. For a market related price, a 1972 price of 2 pence per therm has been employed, escalating at the same rate as the then expected world prices.

By 1982 the BGC had become much more market-related in its attitude towards price negotiations. New legislation also permitted oil companies to bypass the BGC. Consequently, prices of around 20 pence per therm were available (see World Gas Report, 6/12/82, p.8, and 16/8/82, p.4). Price escalation formulae generally relate gas prices to the prices of competitive petroleum fuels. In this exercise the price is escalated at the same pace as the relevant world oil prices projection (see Appendix A).

(g) Inflation Expectations

The same inflation forecasts as were employed for the analysis of the oil projects are used for the gas projects (see B.1.1.(g) above).

(h) Exchange Rate Expectations

The same exchange rates are employed for the analysis of gas projects as for the oil ones (see B.1.1.(h) above).

(i) Fiscal Terms

Fiscal terms applying to gas exploitation in 1972 were the same as those described above for oil (see B.1.1.(i) above). Effective royalty rates as a percentage of the beachhead price are assumed to be 12 percent for the Prolific field and 11.5 percent for the Modest one.[8] In 1982 the PRT (including APRT) applied to new fields. There is a gas allowance allowed for PRT on the same basis as the oil allowance, with the conversion rate being 40,000 cubic feet = 1 ton (see B.1.1.(i) above).

B.2.2. Results of the Analysis

As before, the results are discussed on pre-tax, post-tax, stand alone and post-tax ongoing bases. Again the term tax used below refers to the combination of taxes and royalties.

(a) Pre-Tax

On a pre-tax basis the results of investing in the gas fields discussed above are shown in Table B.7. The same kind of manipulations used to express the results in 1982 United States dollar values for oil were repeated for gas, but note that the gas prices are defined in sterling rather than U.S. dollars.

The results in Table B.7 indicate that under the 1982 Perspective pre-tax returns are very much higher than for the 1972 Perspective, a reflection of real price increases. The pre-tax return for the Modest field under the 1972 controlled price Perspective is minimal.

TABLE B.7

PRE-TAX RETURNS FROM INVESTING IN GAS FIELDS UNDER 1972 AND 1982 PERSPECTIVES (U.S.$ million, 1982 values)

	Prolific Field			Modest Field		
	1972			1972		
	Controlled Price	Market Price	1982	Controlled Price	Market Price	1982
Real Net Present Value						
at 0%	1,367.3	3,343.4	8,731.2	165.2	642.4	1,894.3
at 5%	633.7	1,852.4	4,851.3	28.9	327.0	1,016.6
at 10%	222.4	1,018.4	2,782.1	- 45.9	150.4	548.0
at 15%	- 15.3	530.0	1,610.7	- 87.3	47.8	283.8
Internal Rate of Return (IRR) (%)	14.6	26.7	35.8	6.6	18.7	27.5

(b) Post-Tax Returns, Stand Alone Basis

The post-tax stand alone project returns under the two Perspectives are shown in Tables B.8 and B.9.

Prolific Field

The results indicate that with market prices the Prolific field would be acceptable to investors under the 1972 Perspective. Under the controlled price system, the field would not be acceptable. This latter result conforms with the experience of the 1970s. Of the gas fields in the southern sector developed thus far, the overwhelming majority were approved in the late 1960s. This statement applies to the Hewitt, Indefatigable, Leman, Viking and West Sole. After the upsurge of development work in the late 1960s there was a slump in activity in the 1970s which was only reversed in the 1980s. The results of the 1972 Perspective analysis are consistent with the subsequent events during that decade.

The first half of the 1970s in fact saw a major change in the investment perspective for gas exploitation compared with the late 1960s. In the late 1960s inflation rates were much lower than those expected by investors in 1972. With low expected inflation rates, considerably less

TABLE B.8

PROLIFIC GAS FIELD
REAL 1982 VALUES, STAND ALONE BASIS
(U.S.$ million)

	1972 Perspective		
	Controlled Price	Market Price	1982 Perspective
0% Discount Rate:			
Development Costs	1,011.4	1,011.4	1,400.0
Operating Costs	801.0	902.2	1,388.8
Gross Revenues	3,179.5	5,250.8	11,520.0
Corporation Tax	582.3	1,425.4	1,939.3
Royalties	381.5	630.1	1,382.4
PRT	-	-	3,703.0
Total Tax Take	963.8	2,055.5	7,024.7
Total Tax Take as % Res. Gen.* (%)	70.5	61.6	80.5
Net Present Value	403.2	1,281.7	1,706.5
5% Discount Rate:			
Development Costs	911.3	911.3	1,261.5
Operating Costs	490.1	529.2	781.6
Gross Revenues	2,035.1	3,290.7	6,894.3
Corporation Tax	319.2	800.1	1,116.4
Royalties	244.2	394.9	827.3
PRT	-	-	2,041.5
Total Tax Take	563.4	1,195.0	3,985.2
Total Tax Take as % Res. Gen.* (%)	88.9	64.6	82.2
Net Present Value	70.2	655.2	866.1

* Res. Gen. = Resources Generated = Present Value of Gross Revenue less Development Cost less Operating Cost.

TABLE B.8 (continued)

PROLIFIC GAS FIELD
REAL 1982 VALUES, STAND ALONE BASIS
(U.S.$ million)

	1972 Perspective		
	Controlled Price	Market Price	1982 Perspective
10% Discount Rate:			
Development Costs	827.8	827.8	1,145.8
Operating Costs	320.9	336.7	484.1
Gross Revenues	1,371.0	2,182.0	4,412.0
Corporation Tax	181.9	470.1	677.6
Royalties	164.5	261.8	529.4
PRT	-	-	1,203.5
Total Tax Take	346.4	732.0	2,410.6
Total Tax Take as % Res. Gen.*	(%) 155.8	71.9	86.7
Net Present Value	- 124.1	285.6	371.5
15% Discount Rate:			
Development Costs	757.3	757.3	1,048.2
Operating Costs	222.4	229.0	323.9
Gross Revenues	964.3	1,516.0	2,982.9
Corporation Tax	107.3	287.3	430.3
Royalties	115.7	181.9	358.0
-PRT	-	-	752.2
Total Tax Take	223.0	469.2	1,540.5
Total Tax Take as % Res. Gen.*	(%) (-)	88.6	95.6
Net Present Value	- 238.4	60.4	70.3
Internal Rate of Return (IRR)	(%) 6.5	16.8	16.6

* Res. Gen. = Resources Generated = Present Value of Gross Revenue less Development Cost less Operating Cost.

TABLE B.9

MODEST GAS FIELD
REAL 1982 VALUES, STAND ALONE BASIS
(U.S.$ million)

	1972 Perspective		
	Controlled Price	Market Price	1982 Perspective
0% Discount Rate:			
Development Costs	324.6	324.6	450.0
Operating Costs	269.6	328.0	535.7
Gross Revenues	758.6	1,295.0	2,880.0
Corporation Tax	74.3	273.7	559.4
Royalties	87.2	148.9	331.2
PRT	-	-	515.4
Total Tax Take	161.5	422.7	1,406.0
Total Tax Take as % Res. Gen.*	(%) 98.2	65.8	74.2
Net Present Value	3.0	219.7	488.4
5% Discount Rate:			
Development Costs	292.5	292.5	405.5
Operating Costs	172.2	196.5	301.5
Gross Revenues	493.3	816.0	1,723.6
Corporation Tax	39.2	151.4	308.8
Royalties	56.7	93.8	198.2
PRT	-	-	279.6
Total Tax Take	95.9	245.2	786.6
Total Tax Take as % Res. Gen.*	(%) 335.3	75.0	77.4
Net Present Value	- 67.3	81.8	230.1

* Res. Gen. = Resources Generated = Present Value of Gross Revenue less Development Cost less Operating Cost.

TABLE B.9 (continued)

MODEST GAS FIELD
REAL 1982 VALUES, STAND ALONE BASIS
(U.S.$ million)

	1972 Perspective		1982 Perspective
	Controlled Price	Market Price	
10% Discount Rate:			
Development Costs	265.7	265.7	368.3
Operating Costs	116.2	126.8	186.7
Gross Revenues	335.9	542.9	1,103.0
Corporation Tax	21.4	87.2	179.2
Royalties	38.6	62.4	126.8
PRT	-	-	161.1
Total Tax Take	(%) 60.0	149.7	467.2
Total Tax Take as % Res. Gen.*	-	99.5	85.3
Net Present Value	- 106.0	0.8	80.8
15% Discount Rate:			
Development Costs	243.1	243.1	336.9
Operating Costs	82.3	87.0	125.0
Gross Revenues	237.9	377.9	745.7
Corporation Tax	12.0	52.1	108.6
Royalties	27.4	43.5	85.8
PRT	-	-	97.8
Total Tax Take	39.4	95.6	202.2
Total Tax Take as % Res. Gen.*	(%) (-)	200.0	71.2
Net Present Value	- 126.8	- 47.7	- 8.3
Internal Rate of Return (IRR)	(%) 0.2	10.1	14.4

* Res. Gen. = Resources Generated = Present Value of Gross Revenue less Development Cost less Operating Cost.

than 100 percent compensation through higher gas prices would be acceptable. With a brisker pace of inflation plus the depreciation of sterling against the United States dollar, fuller compensation was necessary to attract positive investment decisions. Lack of such compensation played a role in greatly reducing the level of investment in the 1970s.

Under the 1982 Perspective the Prolific field has a very similar internal rate of return to that in prospect under the 1972 market price assumption. At low rates of discount the 1982 Perspective is more attractive than the 1972 market related one, but as discount rates are increased the net present values approach each other. This follows mainly because real capital costs are much higher under the 1982 Perspective. As higher discount rates are employed, the influence of the larger capital costs under the 1982 scenario become more pronounced. It is interesting to note that although under the 1982 Perspective the Prolific field is faced with considerable front-end fiscal payments (royalty plus APRT) the increase in the total discounted real tax taken at a zero discount rate compared with at a 10 percent rate (81 percent to 87 percent) is relatively less than that experienced under the 1972 market price case. In the latter case the tax take increased from 62 percent to 72 percent. Thus the tax system is not primarily responsible for the changes in the returns to the investor at different discount rates.

The results show that the prospective returns facing the investor in 1982 were much greater than those under the 1972 controlled price conditions. However, in terms of market related price Perspectives they also show that the combination of higher costs and higher taxes effectively tended to absorb much of any increase in economic rents attributable to higher prices under the 1982 Perspective.

Modest Field

For the Modest field the 1982 Perspective is generally more attractive than the 1972 one at market related prices. At low discount rates the expected net present values are greatly in excess of those expected in 1972. The internal rate of return is also greater by an extent which could determine the difference between project acceptance and rejection. This improvement suggests the tax system in 1982 was more sensitive than that in 1972 to variations in reservoir 'quality'. The difference between the 1982 Perspective and the 1972 controlled price one is extremely large.

(c) Post-Tax Returns - Ongoing Basis

The analysis is now extended to cover the position of investors already in tax-paying positions at the time the projects are undertaken. Benefits accrue in the form of postponed corporation tax, as discussed beforehand for the oil fields. The post-tax returns under the 1972 and 1982 Perspectives are shown in Table B.10. There is a marked improvement in discounted post-tax returns under all scenarios. The pattern of changes parallels that found for the oil fields. For all cases the net present values are at noticeably higher levels for both Prolific and Modest fields at all discount rates, with a greater improvement at higher discount rates.

TABLE B.10

RESULTS OF INVESTING IN GAS FIELDS
ON ONGOING BASIS
($ U.S. million, 1982 values)

	Prolific Field			Modest Field		
	1972			1972		
	Controlled Price	Market Price	1982	Controlled Price	Market Price	1982
Real Net Present Value						
at 0%	493.1	1,357.2	1,810.9	36.8	247.0	523.4
at 5%	211.8	776.7	1,033.0	- 15.2	125.1	285.8
at 10%	46.9	435.4	577.2	- 44.6	53.5	149.1
at 15%	- 51.5	227.2	299.4	- 60.9	10.3	67.5
Taxes as % RG (zero discount rate)	63.9	59.3	79.3	77.6	61.5	72.4
PV Taxes as % PVRG* (10% discount rate)	78.9	57.2	79.3	-	64.4	72.8
Internal Rate of Return (IRR) (%)	12.1	25.9	25.7	3.2	16.6	22.4

* PVRG = present value of resources generated.

Under the 1972 Perspective the rate of return increases from 6.5 percent (stand alone) to 12 percent (ongoing) on the Prolific field and from 0.2 to 3.2 percent on the Modest one, given controlled prices. For the Prolific field, the tax take in discounted terms falls from over 100 percent to 79 percent (controlled prices), reflecting the benefits of the accelerated use of capital allowances. With market related prices under the 1972 Perspective the rate of return increases from 17 percent to 26 percent on the Prolific field and from 10 percent to 17 percent on the Modest one.

Under the 1982 Perspective the investor's return increases from 17 percent to 26 percent on the Prolific field and 14 percent to 22 percent on the Modest one. Tax takes in discounted terms (10 percent) are reduced from 87 percent to 79 percent on the Prolific field and from 85 percent to 73 percent on the Modest one. The effect is to prevent the tax take from rising in an ongoing situation when the analysis changes from zero discount rate to 10 percent. This result is in spite of the heavy front-end payments through royalty and APRT under the 1982 fiscal system.

The results indicate that there is not much difference in the relative improvements to the internal rates of return to investors brought about from the ongoing situation in 1972 compared with 1982. Net present values increase rather more under the 1982 Perspective. The value of the corporation tax saved before production is somewhat greater under the 1982 system because it relates to a larger real level of capital expenditure. The corporation tax rate is, of course, constant throughout. The impact of this phenomenon leads to a 5.9 percent improvement in the real net cash flow in the Prolific field under the 1972 (market related) Perspective while under the 1982 Perspective it is 6.1 percent (see Tables B.8 and B.10). However, when discount rates are increased the value of the tax savings under the 1982 Perspective have rather more effect on the net present values. Thus at a 15 percent discount rate the net present value of the Prolific field improves by 276 percent with ongoing project tax savings under the 1972 scenario and by 326 percent under the 1982 one. As expected, the value of the front-end loaded tax savings from ongoing operations increases with the size of the discount rate.

B.3 Comparative Post-Tax Returns in Sterling

Throughout this Appendix the post-tax returns have been shown in United States dollars, but the exercise has been conducted initially in terms of sterling since tax payments to the United Kingdom government are made in that currency. The final real sterling values are converted into United States dollars at the appropriate exchange rate, as discussed in Section B.1. This procedure was adopted to facilitate international comparisons. However, it is interesting to examine the results in sterling terms, especially for an investor in the United Kingdom who (unrealistically) was not concerned with the purchasing power of sterling overseas. The effect of the depreciation of sterling in the 1982 Perspective compared with the 1972 one is to boost oil revenues in sterling terms; it is also possible that the 1982 sterling gas prices do reflect to some extent the depreciation of sterling against the dollar.

The post-tax returns in sterling terms from investing in the oil and gas fields under the two Perspectives are shown in Tables B.11 and B.12. The results highlight the increased size of the net present values in the 1982 Perspective in relation to the 1972 one, compared with the situation when the calculations were done in United States dollars. For example, with regard to the Prolific oil field when the calculation was done in United States dollars the real net present value at 10 percent on the 1982 Perspective was 75 percent higher than under the 1972 one (Optimistic cost). When the calculation was done in sterling terms the net present value under the 1982 Perspective was 145 percent higher than the 1972 one. Similarly, on the Prolific gas field it was found that under the 1982 Perspective the net present value at 10 percent was 30 percent higher than that under the 1972 Perspective in dollar terms. When the calculation was done in sterling the corresponding figure was some 88 percent. But in terms of the internal rate of return (IRR) the sterling results are about the same as the dollar figures.

As indicated above the view taken here is that the dollar calculations give a better presentation of the purchasing power of the investments over the two Perspectives.

B.4 Limitations of Analysis

The analysis has concentrated on the changes in the investment perspectives in the United Kingdom North Sea in 1982 compared to 1972 on the basis of discovered fields. Nothing has been said about exploration costs and incentives, and it is probable that along with development costs, unit exploration costs in real terms have increased over the decade. The overall investment perspective depends not only on expected costs, oil prices and the fiscal regimes including exploration costs, but also on 'prospectivity' - the probability of commercial success. It is likely that prospectivity as far as oil is concerned was at a lower level in 1982 than in 1972. This will have had an effect on the willingness of companies to explore. In other words the perceived chances of finding the fields analysed above are likely to have changed in the period. It is not clear that the prospectivity regarding gas fields has changed in the interval. It is more likely that the expected gas prices in relation to costs and taxes caused a reduction in exploration in the 1970s. The big change in gas prices in the last couple of years is the main factor explaining the upsurge in exploration interest, rather than any change in perceived prospectivity.

TABLE B.11

POST-TAX RETURNS FROM INVESTING IN OIL FIELDS UNDER 1972 AND 1982 PERSPECTIVES, STAND ALONE BASIS (£ million, 1982 values)

	Prolific Field		Modest Field	
Real Net Present Value	1972*	1982	1972*	1982
At 0%	665.4	2,089.6	65.3	307.1
At 5%	339.2	937.4	19.1	93.1
At 10%	145.7	357.0	- 10.5	- 20.5
At 15%	27.5	57.1	- 29.5	- 79.4
Internal Rate of Return (%)	16.6	16.5	7.9	8.8

* optimistic cost case

TABLE B.12

POST-TAX RETURNS FROM INVESTING IN GAS FIELDS UNDER 1972 AND 1982 PERSPECTIVES, STAND ALONE BASIS (£ million, 1982 values)

	Prolific Field		Modest Field	
Real Net Present Value	1972*	1982	1972*	1982
At 0%	567.4	1,074.5	97.7	307.8
At 5%	291.4	549.3	36.9	146.3
At 10%	128.6	240.2	1.2	53.0
At 15%	29.4	51.9	- 20.1	- 2.6
Internal Rate of Return (%)	17.0	16.9	10.2	14.7

* market price case

Footnotes

[1] Note that this results in a higher peak initial reserve: production ratio for the Modest field, a reflection of its more rapid development.

[2] Deflated by the GNE price index (see Table B.2 below).

[3] This tax was not assumed to have been anticipated in 1972.

[4] The 'uplift' effectively increases the eligible capital expenses for write-off by 35 percent.

[5] Note that development and operating costs are almost double in real terms in 1982 compared with 1972.

[6] See above, Section B.1.1.(i); the oil allowance is a fixed one million tonnes per field.

[7] One therm is 100,000 BTUs.

[8] As mentioned above, economies of scale for the Prolific field are assumed to be minor.

APPENDIX C

UNITED STATES (TEXAS AND U.S. OCS): RETURNS ON OIL RESERVOIR INVESTMENTS

Appendix C

UNITED STATES (TEXAS AND U.S. OCS): RETURNS ON OIL RESERVOIR INVESTMENTS

This appendix provides details on the analysis of United States oil reservoir investments discussed in Chapter 1 of CERI Study #20. It was mainly prepared by Alexander Kemp and David Rose, University of Aberdeen, Scotland. To parallel the analysis of Alberta and the North Sea, two sizes of oil reservoirs were examined, termed 'Prolific' and 'Modest'. The material below outlines in detail the assumptions made about both the characteristics of the reservoirs and their associated economic parameters - distinguishing between the 1972 and 1982 Perspectives where appropriate - and then tabulates the economic evaluations. The analysis is conducted for situations appropriate to West Texas (Section C.1) and then for United States Outer Continental Shelf (OCS, Texas) (Section C.2).

C.1. West Texas

C.1.1. Basic Data and Assumptions Employed

(a) Recoverable Reserves and Production Profile

Total recoverable reserves are 2,650 thousand barrels (420 $10^3 m^3$) for the Prolific reservoir and 530 thousand barrels (84 $10^3 m^3$) for the Modest reservoir. Production starts within the same year that development investment is initiated, since the wells are assumed to be on stream a few months after drilling begins. Ten production wells developed over two years are assumed for each reservoir. The production profile shows a three year build up in each well's productivity to a peak of 125 barrels (20 m^3) of oil per day per well in the Prolific field and 25 barrels (4 m^3) of oil per day per well in the Modest field. A decline of 15 percent per year then commences and production stops when the net operating income falls below zero.

(b) Development Costs

The 1972 dollar development costs for the Modest reservoir total 0.7 million United States dollars. The expenses are spread over the first two years equally. In each year 80 percent relates to drilling and

20 percent to tangible completion costs. The drilling costs include a 15 percent allowance for dry development wells. These assumptions represent a cost of $3,148 (US $) per peak daily barrel produced.

For the Prolific reservoir, development costs total 1.6 million United States dollars. The expenses are spread evenly over the first two years. As the Prolific reservoir is deeper, a higher proportion of development costs relate to drilling. Again there is a 15 percent allowance for dry development wells. These assumptions represent a cost of $1,282 (US 1972 $) per peak daily barrel produced. The main source of information for these costs was a Department of the Interior Information Circular.

Both the reservoirs assumed to be developed in 1972 and 1982 were physically identical and the development schedule and production profile were also assumed to be the same. In nominal terms, development costs have risen by a factor of about 3.5 (1972 to 1982); after adjustment for general inflation real costs have risen about 70 percent. Unit costs are some $12,000 (US $) per peak daily barrel produced for the Modest reservoir; for the Prolific reservoir they are some $5,000 (US $) per peak daily barrel produced.

(c) Operating Costs

For the 1972 Perspective annual operating costs are assumed to be $3,000 per well for the Modest field and $4,150 per well for the deeper Prolific field. In 1982, annual operating costs rose to $11,200 per well for the Modest field and $15,400 per well for the Prolific field.

(d) Production Start-up Date

As mentioned above, production was assumed to start the same year development was initiated. This is facilitated by Texas prorationing.

(e) Inflation Rates for Converting 1972 Perspective Results to 1982 Equivalent Values.

The general price index employed to convert the 1972 investment Perspective from 1972 dollars to 1982 dollars is shown in Table C.1.

TABLE C.1
UNITED STATES GNP PRICE INDEX

1972	1.000	1978	1.504
1973	1.057	1979	1.635
1974	1.151	1980	1.786
1975	1.257	1981	1.955
1976	1.324	1982	2.071
1977	1.400		

Source: Statistical Abstract of the United States, Department of Commerce, Bureau of the Census.

(f) Oil Price Expectations

The 1972 starting price for oil in West Texas was set at \$3.25 per barrel (\$20.45 per m^3) the 1982 price was \$32.72 (\$205.90 per m^3). The index of real prices taken from world oil price forecasts used in the Canadian analysis was applied thereafter (see Appendix A, A.1.1.(d)).

(g) Inflation Expectations

A three percent per year inflation expectation was used for the 1972 Perspective. For the 1982 Perspective, expected inflation starts at 7.5 percent in 1983, falls to 7.0 percent in 1984 and is held at 6.5 percent thereafter.

(h) Fiscal Terms

In Texas, mineral rights are privately owned and accordingly royalties accrue to private landlords. From the investor's viewpoint they are equivalent to a fiscal imposition.

For the 1972 Perspective a royalty rate of 12-1/2 percent of wellhead values was used. Moreover, the State of Texas imposed two production taxes. The more important of these was at the rate of 4.6 percent of the value of production. The second one was a Regulatory Tax at the rate of 3/16 of 1 cent per barrel. Texas did not have a State income tax. Investors were subject to Federal Income Tax. In 1972 these income tax rates were 22 percent on the first \$25,000 of taxable income and 48 percent on income above that level. An investment tax credit equal to 7 percent of tangible capital expenditures was available. A depletion allowance equal to 22 percent of gross revenues up to a maximum of 50 percent of net income was also allowed.

For the 1982 Perspective the royalty was assumed to be at a rate of 16-2/3 percent, reflecting the average general increase over the period. The production and regulatory taxes were unchanged. The rates of Federal Income Tax were as follows:

Taxable Income ($)	Tax Rate (%)
25,000	17
25,000 - 50,000	20
50,000 - 75,000	30
75,000 - 100,000	40
100,000	46

An investment tax credit equal to 10 percent of tangible capital expenditures was available. Depreciation rates were as allowed under the Accelerated Cost Recovery System introduced in the Economic Recovery Tax Act of 1981. Under this system costs are recovered over a five year period. The Federal Income Tax is on a company basis with no ring fence provisions.

In 1980 the Windfall Profits Tax (WPT) was enacted. It is essentially a temporary excise or severance tax on all production of domestic crude oil. The amount of tax payable varied with the classification of taxable crude oil into one of three tiers. It is assumed that Tier Three oil is the relevant category for the 1982 Perspective. This refers to oil discovered in 1979 or after. The amount of windfall profit generated by a barrel of oil is the amount by which the actual sales price exceeds the adjusted base price. The Tier Three base price was $16.55 for May 1979 and is adjusted annually by a factor equal to the inflation rate plus 2 percent. An adjustment for state severance taxes is allowed in determining the liability for WPT. This adjustment equals the amount by which the actual severance tax exceeds the severance tax that would have been payable if the oil had been sold at the adjusted base price. The WPT is a deductible expense for Federal Income Tax purposes. In the Economic Recovery Act of 1981 the rates of WPT were reduced for Tier Three oil to 27-1/2 percent in 1982, 25 percent in 1983, 22-1/2 percent in 1984, 20 percent in 1985 and 15 percent in 1986 and thereafter. Assumptions had to be made about phaseout. It was assumed that the rate would drop to 12 percent in 1991, 8 percent in 1992 and 5 percent 1993. At the end of that year it was assumed to cease.

C.1.2. Results of the Analysis

The evaluations were conducted on a pre-tax and royalty basis, and in terms of two post-tax and royalty situations. The first was on a 'stand alone' basis where the company did not have any other existing income. The second was an 'ongoing' one where the company did enjoy the benefits of immediate relief for development costs at the rates allowed under the depreciation schedules.

Hereafter the term tax refers to the combination of taxes and royalties.

(a) Pre-Tax Results

On a pre-tax and royalty basis the projects described above result in expected real rates of return (IRR) for the Prolific field under the 1972 Perspective of 58.4 percent while the net present value at 10 percent is $6.6 million (1982 $). The Modest field under the 1972 Perspective has an expected rate of return of 22 percent and a net present value at 10 percent of $0.7 million (1982 $). Under the 1982 Perspective the Prolific field has an expected return of 134 percent with net present value at 10 percent of $35 million (1982 $). The Modest field offers a 63 percent rate of return and net present value of some $6.7 million (1982 $). Details are shown in Table C.2.

TABLE C.2

REAL PRE-TAX RETURNS FROM INVESTING IN OIL FIELDS
UNDER 1972 AND 1982 PERSPECTIVES
(U.S.$ million - 1982 values)

	Prolific Field		Modest Field	
	1972	1982	1972	1982
Real Net Present Value				
at 0%	12.4	60.6	2.0	13.5
at 5 %	9.0	45.3	1.2	9.3
at 10%	6.6	35.0	0.7	6.7
at 15%	4.9	27.9	0.3	5.0
Internal Rate of Return (%)	58.4	133.8	22.0	63.0

(b) Post-Tax Stand Alone Basis

The post-tax positions are shown in Tables C.3 (Prolific Field) and C.4 (Modest Field).

Prolific Field

For the Prolific field the investor is clearly better off under the 1982 Perspective. This is despite the increases in real development costs and taxes over the period. Increased oil prices have more than compensated for these increased burdens. The real development cost increases have been quite substantial at around 90 percent at 1982 prices. The fiscal burden has been increased through higher royalties, the WPT and the loss of the depletion allowance for Federal Income Tax. The impact of the WPT is very much less on Tier Three oil than on Tier One, for example, where the rate is 70 percent. This was deliberate Government policy which has had the objective of fostering new exploration and development in the oil sector. The yield of the Windfall Profits Tax is seen from Table C.3 to be comparatively small.

The level of tax takes in Texas are low by international standards under both the 1972 and 1982 Perspectives. Under the 1972 Perspective the tax take increases slightly as the rate of discount applied to the pre-tax net present value and the tax bill is increased. This reflects the increased weight of the royalty and production taxes which of course commence when production does. Under the 1982 Perspective the tax take is consistently higher at all discount rates than it is under the 1972 situation. The difference in burden in percentage terms is moderate and the 1982 takes remain low by international standards.

The relative advantage for the investor under the 1982 Perspective over the 1972 one does not vary significantly with the real discount rate employed for a range of rates up to 15 percent. The multiple for the increase in net present value under the 1982 Perspective over the 1972 one is always between about 4 and 5.

TABLE C.3

TEXAS PROLIFIC OIL RESERVOIR
REAL 1982 VALUES, STAND ALONE BASIS
(U.S.$ million)

	1972 Perspective	1982 Perspective
0% Discount Rate:		
Development Costs	3.2	6.1
Operating Costs	1.5	5.4
Gross Revenues	17.1	69.9
Income Tax	3.1	19.2
Royalties	2.1	11.7
PRT	0.7	2.8
Windfall Profit Tax	-	1.5
Total Tax Take	5.9	35.1
Total Tax Take as % Res. Gen.*	(%) 47.6	58.0
Net Present Value	6.5	25.5
5% Discount Rate:		
Development Costs	3.1	5.9
Operating Costs	0.9	1.9
Gross Revenues	13.0	53.1
Income Tax	2.2	13.7
Royalties	1.6	8.9
PRT	0.5	2.0
Windfall Profit Tax	-	1.2
Total Tax Take	4.3	25.8
Total Tax Take as % Res. Gen.*	(%) 48.2	57.1
Net Present Value	4.6	19.4

* Res. Gen. = Resources Generated = Present Value of Gross Revenue less Development Cost less Operating Cost.

TABLE C.3 (continued)

TEXAS PROLIFIC OIL RESERVOIR
REAL 1982 VALUES, STAND ALONE BASIS
(U.S.$ million)

	1972 Perspective	1982 Perspective
10% Discount Rate:		
Development Costs	3.0	5.8
Operating Costs	0.7	1.3
Gross Revenues	10.3	42.1
Income Tax	1.6	10.2
Royalties	1.3	7.0
PRT	0.4	1.6
Windfall Profit Tax	-	1.0
Total Tax Take	3.3	19.8
Total Tax Take as % Res. Gen.*	(%) 49.6	56.5
Net Present Value	3.3	15.2
15% Discount Rate:		
Development Costs	2.9	5.7
Operating Costs	0.5	0.9
Gross Revenues	8.4	34.5
Income Tax	1.2	7.8
Royalties	1.0	5.8
PRT	0.3	1.3
Windfall Profit Tax	-	0.8
Total Tax Take	2.6	15.7
Total Tax Take as % Res. Gen.*	(%) 51.8	56.3
Net Present Value	2.4	12.2
Internal Rate of Return (IRR)	(%) 41.0	90.8

* Res. Gen. = Resources Generated = Present Value of Gross Revenue less Development Cost less Operating Cost.

TABLE C.4

TEXAS MODEST OIL RESERVOIR
REAL 1982 VALUES, STAND ALONE BASIS
(U.S.$ million)

	1972 Perspective	1982 Perspective
0% Discount Rate:		
Development Costs	1.4	2.6
Operating Costs	0.9	3.9
Gross Revenues	4.3	18.4
Income Tax	0.3	4.0
Royalties	0.5	3.1
PRT	0.3	0.7
Windfall Profit Tax	-	0.3
Total Tax Take	1.1	8.1
Total Tax Take as % Res. Gen.*	(%) 53.4	60.5
Net Present Value	0.9	5.3
5% Discount Rate:		
Development Costs	1.3	2.5
Operating Costs	0.6	1.4
Gross Revenues	3.2	13.3
Income Tax	0.2	2.7
Royalties	0.4	2.2
PRT	0.1	0.5
Windfall Profit Tax	-	0.3
Total Tax Take	0.8	5.7
Total Tax Take as % Res. Gen.*	(%) 62.5	60.8
Net Present Value	0.5	3.6

* Res. Gen. = Resources Generated = Present Value of Gross Revenue less Development Cost less Operating Cost.

TABLE C.4 (continued)

TEXAS MODEST OIL RESERVOIR
REAL 1982 VALUES, STAND ALONE BASIS
(U.S.$ million)

	1972 Perspective	1982 Perspective
10% Discount Rate:		
Development Costs	1.3	2.5
Operating Costs	0.5	0.9
Gross Revenues	2.5	10.1
Income Tax	0.2	1.9
Royalties	0.3	1.7
PRT	0.1	0.4
Windfall Profit Tax	-	0.2
Total Tax Take	0.6	4.1
Total Tax Take as % Res. Gen.*	(%) 80.8	60.5
Net Present Value	0.1	2.5
15% Discount Rate:		
Development Costs	1.3	2.4
Operating Costs	0.3	0.7
Gross Revenues	2.0	8.1
Income Tax	0.1	1.3
Royalties	0.2	1.3
PRT	0.1	0.3
Windfall Profit Tax	-	0.2
Total Tax Take	0.4	3.1
Total Tax Take as % Res. Gen.*	(%) 127.8	64.3
Net Present Value	- 0.1	1.7
Internal Rate of Return (IRR)	(%) 12.7	38.5

* Res. Gen. = Resources Generated = Present Value of Gross Revenue less Development Cost less Operating Cost.

Modest Field

The Modest reservoir remains distinctly more attractive under the 1982 Perspective than under the 1972 one. On a pre-tax basis it is seen from Table C.2 that the Modest field under the 1982 Perspective was comparatively more attractive in relation to the 1972 one than the Prolific Field was under the 1982 Perspective compared with the 1972 one. The impact of the fiscal system in Texas enhances this feature, especially at higher discount rates. Table C.4 shows that the tax take (in percentage terms) increases rapidly to very high levels under the 1972 Perspective: the increase is from 53 percent at zero discount rate to 128 percent at a 15 percent rate. Under the 1982 Perspective the take (in percentage terms) increases only gently from 61 percent to 64 percent at the same discount rates. Although the fiscal take in Texas is not at high levels, under the 1972 Perspective the burden on a marginal field becomes serious especially at high discount rates. This is due to the royalty and production taxes which are not related to profits. Under the 1982 Perspective the field is inherently more profitable and the burden of all forms of production-based taxes and excises such as the WPT becomes less (in percentage terms) in all cases.

(c) Post-Tax Ongoing Basis

Frequently, investors in new oil fields are already in a tax-paying position and there can be substantial advantages to such investors compared with new entrants. In the case of Texas the investor is able to obtain relief for his intangible drilling costs on 100 percent first year basis as soon as the expenditure is incurred. He can set such expenditures against other income and save Federal Income Tax due from other projects. Depreciation allowances may also be set against other income, but relief is delayed until the asset is placed in service. The advantages in the timing of tax reliefs are not so great in the case of onshore Texas because the time period between drilling and production is very short.

In Table C.5 the post-tax returns to an investor already in a tax-paying position are shown. On the Prolific field the improvements in the investor's position are seen to be very modest at low discount rates.

The gains rise with the rate of discount because at higher rates the given front-end relief becomes comparatively more valuable in relation to more distant income and taxes. The early relief is also more valuable in less profitable situations. Thus in the 1972 Perspective the tax take at a 10 percent discount rate falls from 50 percent on a stand alone project basis (see Table C.3) to 44 percent on an ongoing basis.

TABLE C.5

TEXAS
RESULTS OF INVESTING IN OIL RESERVOIRS ON ONGOING BASIS
(U.S.$ million - 1982 values)

	Prolific Reservoir		Modest Reservoir	
	1972	1982	1972	1982
Real Net Present Value				
at 0%	6.7	25.7	1.0	5.4
at 5%	4.9	19.8	0.6	3.8
at 10%	3.7	15.7	0.3	2.8
at 15%	2.8	12.7	0.09	2.0
Taxes as % RG (zero discount rate)	45.7	57.6	47.9	59.7
PV Taxes as % PVRG (10% discount rate)	44.0	55.3	56.5	58.8
Internal Rate of Return (%)	57.8	124.3	17.9	50.5

PVRG = Present Value of Resources Generated

On the Modest reservoir the improvements to the investor's position are seen to be relatively greater than on the Prolific field. As was indicated above a given amount of front-end relief is relatively more valuable to a low profitability field than to a Prolific one. This factor obviously operates more powerfully at higher discount rates. The rates of return on the Modest reservoir are thus enhanced very considerably. Under the 1972 Perspective the difference could be sufficient to ensure that a field which was not commercially viable on a stand alone basis would become acceptable for an ongoing situation: the rate of return improves from 12.7 percent to 17.9 percent. Under the 1982 Perspective the reservoir becomes very attractive.

C.2. United States OCS (Texas)

C.2.1. Basic Data and Assumptions Employed

(a) Recoverable Reserves and Production Profile

Total recoverable reserves are set at 32 million barrels (5 $10^6 m^3$) on the Prolific Field and 18.5 million barrels (3 $10^6 m^3$) for the Modest field. Production starts in the fourth year after development investment is initiated. There is a two year build up to peak production on both fields. On the Prolific reservoir, plateau output is 12,000 b/d (1,900 m^3/d). This rate is maintained for two years after which there is a decline rate of 15 percent annually over a period of 18 years. The Modest reservoir has a peak production of 7,000 b/d (1,112 m^3/d) which is maintained for one year. The decline rate is also 15 percent per year over a period of 16 years.

(b) Development Costs

For the 1972 Perspective total development costs of $2,260 per plateau daily barrel at real 1972 prices have been assumed for the Prolific field. For the Modest field a figure of $3,800 (at real 1972 prices) per plateau daily barrel has been used. For the 1982 Perspective total development costs of $8,000 per plateau daily barrel (at 1982 prices) have been used while on the Modest field the corresponding figure is $13,000 per plateau daily barrel (again at 1982 prices). These figures have been constructed with the assistance of a major oil company with long experience in production operations in many parts of the US OCS. Real development costs increase by a factor of 1.7 over the period 1972 to 1982.

The structure and phasing of development costs for the two fields were also determined in consultation with a major oil company. On both fields drilling and intangible development costs constituted 78 percent of total development costs. The phasing of the costs is shown in Table C.6.

TABLE C.6

PHASING OF OCS OIL FIELD DEVELOPMENT EXPENDITURES*
(1972 AND 1982 PERSPECTIVES, BOTH FIELDS)
(real terms)

Time Period Year	% of Total Capital Expenditure	% of Total Drilling Costs
1	5	
2	15	
3	25	30
4	30	30
5	25	30
6		10

* Total development costs represent drilling plus all other capital costs.

(c) Operating Costs

Operating costs are assumed to be 7 percent of total accumulated development costs for both fields under both the 1972 and 1982 Perspectives.

(d) Production Start-Up Date

For both fields and both investment Perspectives the production start-up date is year 4 (with year 1 being the first year of capital expenditure).

(e) Inflation Rates for Converting 1972 Perspective Results to 1982 Equivalent Values

The actual inflation rates used to convert results calculated in 1972 US $ to 1982 US $ are the same for offshore Texas as for onshore shown in Table C.1.

(f) Oil Price Expectations

The 1972 oil price for Texas offshore was set at $3.24 per barrel ($20.39 per m^3) with the quality margin between Texas offshore prices and West Texas crude prices being held at the same proportion between 1972 and 1982. The index used thereafter was derived from the world oil price forecast used for the Canadian analysis (see Appendix A).

The 1982 offshore price was set at $32.62 per barrel ($205.25 per m^3). This was projected to increase at the same rate as that anticipated for world oil prices (see Appendix A, A.1.1.(d)).

(g) Inflation Expectations

As for the onshore analysis, the 1972 inflation expectations were 3 percent per year. The 1982 expectations were also the same as those for onshore, assumed to be 7.5 percent in 1983, 7.0 percent in 1984 and 6.5 percent thereafter.

(h) Fiscal Terms

The fiscal terms incorporate royalties of 12.5 percent and 16.66 percent, respectively, for the Modest and Prolific reservoirs. The Federal Income Tax provisions and Windfall Profits Tax regulations are as described above in Section C.1.1.(h). No state production or other taxes are levied on operations in the United States OCS.

C.2.2. Results of the Analysis

The evaluations were initially conducted on a pre-tax and royalty basis and subsequently on post-tax terms both on a 'stand alone' basis and on an 'ongoing' basis as described in Section C.1.2 above. The pre-tax results are shown in Table C.7 and the post-tax ones in Table C.8 (Prolific field) and Table C.9 (Modest field).

TABLE C.7

UNITED STATES OCS (TEXAS)
REAL PRE-TAX RETURNS FROM INVESTING IN OIL FIELDS
UNDER 1972 AND 1982 PERSPECTIVES
(U.S.$ million - 1982 values)

	Prolific Field		Modest Field	
Real Net Present Value	1972	1982	1972	1982
at 0%	134.7	799.5	34.9	383.7
at 5%	84.2	518.0	16.6	245.0
at 10%	53.5	351.8	5.8	162.2
at 15%	34.2	247.8	- 0.8	110.1
Internal Rate of Return (%)	41.6	104.6	14.2	63.1

TABLE C.8

UNITED STATES OCS (TEXAS) PROLIFIC OIL FIELD
REAL 1982 VALUES, STAND ALONE BASIS
(U.S.$ million)

	1972 Perspective	1982 Perspective
0% Discount Rate:		
Development Costs	54.6	96.0
Operating Costs	55.7	131.5
Gross Revenues	244.5	1,026.4
Income Tax	30.5	259.4
Royalties	30.5	171.1
Windfall Profit Tax	-	13.3
Total Tax Take	61.1	443.8
Total Tax Take as % Res. Gen.*	(%) 45.6	55.5
Net Present Value	73.0	355.1
5% Discount Rate:		
Development Costs	47.2	83.0
Operating Costs	34.6	73.5
Gross Revenues	165.7	674.3
Income Tax	19.0	159.9
Royalties	20.7	112.4
Windfall Profit Tax	-	9.5
Total Tax Take	39.7	281.9
Total Tax Take as % Res. Gen.*	(%) 47.3	54.4
Net Present Value	44.2	235.9

* Res. Gen. = Resources Generated = Present Value of Gross Revenue less Development Cost less Operating Cost.

TABLE C.8 (continued)

UNITED STATES OCS (TEXAS) PROLIFIC OIL FIELD
REAL 1982 VALUES, STAND ALONE BASIS
(U.S.$ million)

	1972 Perspective	1982 Perspective
10% Discount Rate:		
Development Costs	41.2	72.5
Operating Costs	22.8	45.2
Gross Revenues	117.4	469.4
Income Tax	12.2	103.8
Royalties	14.7	78.2
Windfall Profit Tax	-	6.9
Total Tax Take	26.9	189.0
Total Tax Take as % Res. Gen.*	(%) 50.4	53.7
Net Present Value	26.5	162.7
15% Discount Rate:		
Development Costs	36.3	63.8
Operating Costs	15.8	30.0
Gross Revenues	86.2	341.5
Income Tax	8.1	70.2
Royalties	10.8	56.9
Windfall Profit Tax	-	5.2
Total Tax Take	18.9	132.3
Total Tax Take as % Res. Gen.*	(%) 55.4	53.4
Net Present Value	15.2	115.4
Internal Rate of Return (IRR)	(%) 29.4	76.7

* Res. Gen. = Resources Generated = Present Value of Gross Revenue less Development Cost less Operating Cost.

TABLE C.9

UNITED STATES OCS (TEXAS) MODEST OIL FIELD
REAL 1982 VALUES, STAND ALONE BASIS
(U.S.$ million)

	1972 Perspective	1982 Perspective
0% Discount Rate:		
Development Costs	53.6	91.0
Operating Costs	43.4	112.0
Gross Revenues	131.3	586.4
Income Tax	4.3	115.4
Royalties	16.4	97.7
Windfall Profit Tax	-	7.7
Total Tax Take	20.8	220.8
Total Tax Take as % Res. Gen.*	(%) 60.4	57.6
Net Present Value	13.6	162.6
5% Discount Rate:		
Development Costs	46.3	78.7
Operating Costs	28.8	65.2
Gross Revenues	91.5	388.8
Income Tax	2.5	70.5
Royalties	11.4	64.8
Windfall Profit Tax	-	5.6
Total Tax Take	13.9	140.9
Total Tax Take as % Res. Gen.*	(%) 85.1	57.5
Net Present Value	2.4	104.0

* Res. Gen. = Resources Generated = Present Value of Gross Revenue less Development Cost less Operating Cost.

TABLE C.9 (continued)

UNITED STATES OCS (TEXAS) MODEST OIL FIELD
REAL 1982 VALUES, STAND ALONE BASIS
(U.S.$ million)

	1972 Perspective	1982 Perspective
10% Discount Rate:		
Development Costs	40.4	68.7
Operating Costs	19.9	41.2
Gross Revenues	66.0	272.0
Income Tax	1.5	45.1
Royalties	8.2	45.3
Windfall Profit Tax	-	4.1
Total Tax Take	9.7	94.5
Total Tax Take as % Res. Gen.*	(%) 173.4	58.3
Net Present Value	- 4.1	67.7
15% Discount Rate:		
Development Costs	35.6	60.5
Operating Costs	14.3	27.8
Gross Revenues	49.0	198.4
Income Tax	0.9	29.9
Royalties	6.1	33.1
Windfall Profit Tax	-	3.0
Total Tax Take	7.0	66.0
Total Tax Take as % Res. Gen.*	(%) (-)	59.9
Net Present Value	- 8.0	44.1
Internal Rate of Return (IRR)	(%) 6.6	41.7

* Res. Gen. = Resources Generated = Present Value of Gross Revenue less Development Cost less Operating Cost.

(a) Pre-Tax and Royalty Results

On a pre-tax and royalty basis the projects described above result in real rates of return for the Prolific field under the 1972 Perspective of 42 percent and 105 percent under the 1982 Perspective. The real net present values at 10 percent are $54 million (1982 $) under the 1972 Perspective and $352 million under the 1982 outlook (1982 $). The Modest field under the 1972 Perspective has an expected real rate of return of 14 percent and one of 63 percent under the 1982 outlook. The expected real net present values at 10 percent were $6 million under the 1972 Perspective (1982 $) and $162 million under the 1982 Perspective (1982 $).

(b) Post-Tax, Stand Alone Basis

On the Prolific field the investor is clearly better off under the 1982 Perspective. The net present values at all discount rates are greatly in excess of those under the 1972 Perspective. At zero (real) discount rates the net present value for the 1982 outlook is some five times that of the 1972 one. At a 15 percent rate the corresponding factor is about eight.

The impact of the fiscal system contributes to this result. The tax take (in percentage terms) under the 1972 Perspective increases as the discount rate increases with the figures being 46 percent at a zero (real) discount rate and 55 percent at a 15 percent rate. Under the 1982 Perspective the take actually falls from 56 percent at a zero discount rate to 53 percent at a 15 percent rate. Under the 1972 Perspective the result is achieved through the increased weight of the royalty both in the structure of the tax take and as a proportion of the pre-tax cash flow at higher discount rates. Since royalties are based on gross receipts, they are relatively more punitive on less profitable fields than on Prolific ones and their impact becomes more severe the higher the discount rate because they commence with the first barrel of production. Thus at a 15 percent discount rate the royalty constitutes 57 percent of the total tax take under the 1972 Perspective and only 43 percent of the total under the 1982 outlook at the same discount rate. This is despite the increase in the rate of royalty over the period. The Windfall Profits Tax (WPT) is seen to make only a small contribution to the tax burden under the 1982 Perspective. Without this imposition the tax take would have been 53.9 percent instead of 55.5 percent at a zero discount rate and 51.3 percent instead of 53.4 percent at a 15 percent rate. It is clear that this tax has not compensated for the increased windfall gains in 1982 compared to 1972 through higher expected oil prices.

Modest Field

On the Modest field it is also clear that the investor is much better off under the 1982 Perspective. At all discount rates the differential in favour of the 1982 outlook is very large. The fiscal system contributes markedly to the results. The tax take (in percentage terms) is higher at all discount rates under the inherently less profitable 1972 outlook. Further, the take escalates rapidly with the discount rate under the 1972 Perspective to reach dramatic proportions at 10 percent where the take is 173 percent, while the increase on the Prolific field is very minor, rising from 58 percent at zero rate to 60 percent at 15 percent.

The explanation for this outcome has already been given in the discussion of the Prolific field. At low levels of profitability (1972 Perspective) imposts based on gross revenues load relatively greater burdens on marginal fields than on Prolific ones. Because payments start with first production the weight of the burden also increases with the discount rate. On a more profitable field the relative burden of the royalty is much less. The minor burden of the Windfall Profits Tax also contributes to the comparative results. Thus at a 10 percent discount rate the tax take would have been 56 percent instead of 58 percent in the absence of this tax and the net present value would have been $72 million instead of $68 million.

(c) Post-Tax, Ongoing Basis

As was discussed in Section C.1.2. above investors already in a taxpaying position can operate at an advantage compared with new entrants. The basis of the advantage in the United States OCS is the same as that for an investor in Texas. The results for the two fields under the two Perspectives are shown in Table C.10.

TABLE C.10

UNITED STATES OCS (TEXAS)
RESULTS OF INVESTING IN OIL FIELDS ON ONGOING BASIS
UNDER 1972 AND 1982 PERSPECTIVES
(U.S.$ million - 1982 values)

	Prolific Field		Modest Field	
	1972	1982	1972	1982
Real Net Present Value				
at 0%	83.4	356.7	23.4	164.5
at 5%	53.1	243.9	11.1	110.2
at 10%	34.2	165.6	3.5	71.1
at 15%	21.9	118.6	-1.3	47.8
Taxes as % RG (0% Discount Rate)	37.8	55.4	31.8	57.1
PV Taxes as % PV RG (10% Discount Rate)	36.0	52.9	37.6	56.2
Internal Rate of Return (%)	38.2	88.3	13.4	49.0

PVRG = Present Value of Resources Generated

It is clear that in both Perspectives the Prolific and Modest fields benefit considerably from being exploited in an ongoing situation. Also the advantages of the early tax relief become greater the higher the discount rates employed in the calculation. Thus at a 10 percent rate the tax take on the Prolific field falls from 50 percent on a stand alone basis to 36 percent on an ongoing basis under the 1972 scenario but only marginally from 54 percent to 53 percent under the 1982 Perspective. Similarly, on the Modest field the take falls from 173 percent to 38 percent under the 1972 outlook and from 58 percent to 56 percent on the 1982 Perspective.

The benefits from ongoing operations to the investor exploiting an inherently poor field are strikingly greater than those accruing to an investor in a highly profitable one. The tax systems are seen from Table C.10 to become less regressive when viewed on an ongoing basis. The expected rate of return on the Modest field (1972 Perspective) is seen to broadly double when undertaken on an ongoing basis instead of as a stand alone project. The expected return on the most profitable Perspective (Prolific field, 1982 outlook) in contrast increases from 77 percent to 88 percent. The variation between the expected returns under the 1982 Perspective compared with the 1972 one is significantly reduced when viewed on an ongoing basis. Nevertheless the differential in favour of 1982 remains significant.

C.3 Limitations of Analysis

The analysis has concentrated on the changes in the investment scene between 1972 and 1982 for new oil reservoirs in the United States (Texas). Of course, the inclusion of exploration costs would reduce all returns by amounts varying not only by the relative tax treatment of exploration costs between the two years, but also by changes in the amount of exploration inputs required to discover a commercial deposit. The reservoirs discussed above represent two possible outcomes of the exploration gamble.

An overall industry perspective would relate to aggregate expectations, the probability weighted sum of all possible outcomes. These probabilities, primarily representing the geological risks of discovery, are difficult to quantify. But logically over time the probability of discovering new large fields must tend to decline in the absence of innovative discovery techniques and the availability of new exploration plays. The onshore West Texas area is in a sufficiently mature phase so that depletion effects are no doubt manifest. The younger offshore industry may not yet have reached that point.

The likelihood is, then, that the more attractive returns at the reservoir development state estimated under the 1982 Perspective will be partially and could even be wholly absorbed by higher costs of exploration, especially in the case of West Texas.

APPENDIX D

CALCULATION OF RATES OF RETURN, SELECTED CANADIAN INDUSTRIES

Appendix D

CALCULATION OF RATES OF RETURN, SELECTED CANADIAN INDUSTRIES

This Appendix outlines the procedures used to estimate achieved nominal and real rates of return over the period 1972 to 1980 for the following industries:

- oil and gas production
- manufacturing
- mining (excluding oil and gas wells)
- utilities.

It supplements the information in Chapter 2 of CERI Study #20.

The need to determine real as opposed to merely apparent rates of return is fundamental to any understanding of industry performance over periods when inflation is endemic. The overall intention is to restore profitability measures to what they would have been in the absence of inflation.

The nature of the various adjustments made to estimate real rates of return is discussed in what follows, dealing first with the way income is defined, then with the effects of inflation.[1] Next the formulae used to calculate real and nominal rates are specified; finally the sources of data employed are listed.

D.1 The Income Concept

The continued existence of a firm entails maintaining its ability to operate. In this vein, a firm's profit is defined as the maximum amount it could distribute to its owners after making sufficient provision to leave the firm as well off at the end of the period as at the beginning. We call this concept of income the 'capital maintenance concept'.

Accounting tradition focusses on operating income derived from selling certain assets (goods produced) and not others (capital assets). Consequently, changes in market values of capital assets and debt instruments are not relevant to accounting income since the latter concerns realized rather than unrealized profits. Another facet of traditional accounting practice is the principle of matching current costs with current revenues.

These traditional approaches work reasonably well when the purchasing power of money is relatively stable, but when inflation is chronic they can lead to serious distortions.

D.2 Effects of Inflation

Inflation introduces a wedge between conventional accounting profits and real profits. The adjustments for inflation discussed below are patterned on the capital maintenance concept of income, and as mentioned above they are intended to provide the same measure of income as would conventional accounting if prices had remained stable.

D.2.1. Depreciation Adjustments

The primary purpose of a depreciation charge is to account for the decline in the value of an asset as it ages. Accounting tradition treats depreciation as a method of cost allocation; simultaneously, the accounting entries have the function of providing the firm with sufficient funds for asset replacement - an obvious corollary of the capital maintenance concept.

Conventional accounting and Canadian income tax rules have treated depreciation as a function of historical cost. Viewed in terms of capital maintenance, inflation makes such depreciation charges inadequate since there will be a growing wedge between historical and replacement cost. Compensation for inflation requires treating depreciation as a function of replacement cost, not historical cost.

The basic procedure for calculating depreciation expense on a replacement cost basis involves adjusting the acquisition cost of depreciable assets to reflect current replacement costs. Accordingly, the actual (historical) costs of assets acquired in each year must be redefined by applying a price index representing the cumulative price change from the year of acquisition to the current year. This provides an estimate of the current replacement cost value of all the firm's assets. Current (replacement cost) depreciation expense is calculated by applying the appropriate rate of depreciation to current replacement cost.

These manipulations can be laid out as follows. Suppose

H^i_t = historical cost of i^{th} type of asset acquired in year t, $i=1, \ldots m$, $t=1, \ldots n$

P^i_{tn} = price index for asset group i from year t, the date of acquisition, to year n, the current year

d_i = rate of depreciation, asset group i.

Then the current year replacement cost value of company's assets (R_n) is estimated as

$$R_n = \sum_{i=1}^{m} \sum_{t=1}^{n} P^i_{tn} H^i_t \qquad (1)$$

and the total current year replacement cost depreciation change (D_n) is

$$D_n = \sum_{i=1}^{m} d_i \sum_{t=1}^{n} P^i_{tn} H^i_t \qquad (2)$$

The inflation adjusted depreciation expense (D_n) of course enters as a deduction from the income numerator in the rate of return calculation (see later). The associated assets (R_n) enter the denominator for each year as the undepreciated portion of current year's replacement cost. These asset values must be reduced by accumulated depreciation calculated entirely on the basis of current year replacement values. This accumulated depreciation expense - assuming continual inflation - will exceed the sum of annual booked replacement cost depreciation. The difference is called 'backlog' depreciation. For an individual asset group, say asset group i, an expression for backlog depreciation is derived below, on the assumption of straight line depreciation rates.

The series of terms for current year cumulative replacement cost depreciation are as follows:

Year 1 $d_iH_1^i$

Year 2 $2d_iH_1^iP_{12}^i + d_iH_2^i$

Year 3 $3d_iH_1^iP_{13}^i + 2d_iH_2^iP_{23}^i + d_iH_3^i$

|
|
|
|

Year t $td_iH_1^iP_{1t}^i + (t-1)d_iH_2^iP_{2t}^i + (t-2)d_iH_3^iP_{3t}^i + \ldots d_iH_t^i$

$$= d_i \sum_{k=1}^{t} (t+1-k)\, H_k^iP_{kt}^i \qquad (3)$$

(note $P_{tt}^i = 1$)

The expression for 'booked' cumulative replacement cost depreciation is derived from summing the various D expressions (see (2)).

Year 1 $d_iH_1^i$

Year 2 $d_iH_1^i + d_iH_1^iP_{12}^i + d_iH_2^i$

Year 3 $d_iH_1^i + d_iH_1^iP_{12}^i + d_iH_1^iP_{13}^i + d_iH_2^i + d_iH_2^iP_{23}^i + d_iH_3^i$

$$= d_iH_1^i(1+P_{12}^i + P_{13}^i) + d_iH_2^i(1+P_{23}^i) + d_iH_3^i$$

|
|
|
|

Year t $= d_iH_1^i(1 + P_{12}^i + P_{13}^i + \ldots. + P_{1t}^i) + d_iH_2^i(1 + P_{23}^i + P_{24}^i \ldots P_{2t}^i)$

$$+ d_iH_3^i(1+P_{34}^i+P_{35}^i+ \ldots P_{3t}^i) + \ldots + d_iH_t^i = d_i \sum_{k=1}^{t} H_k^i \sum_{j=k}^{t} P_{kj}^i \qquad (4)$$

(recall $P_{kk}^i = 1$)

Thus the general expression for backlog depreciation (BLD), year t, is the difference between the respective general terms for current year cumulative replacement cost depreciation (expression (3)) and 'booked' cumulative replacement cost depreciation (expression (4))

$$\begin{aligned} BLD_t &= d_i \left[\sum_{k=1}^{t} (t+1-k)\, H_k^i P_{kt}^i - \sum_{k=1}^{t} H_k^i \sum_{j=k}^{t} P_{kj}^i \right] \\ &= d_i \left[\sum_{k=1}^{t} H_k^i \left[(t-k) P_{kt}^i - \sum_{j=k}^{t-1} P_{kj}^i \right] \right] \end{aligned} \qquad (5)$$

An alternative technique which avoids any need to adjust for backlog depreciation is to focus more directly on estimates of replacement cost depreciation to be deducted from gross replacement cost asset values. Setting aside for the moment the question of data availability, the current year cumulative replacement cost depreciation for an industry where we do not distinguish between different types of assets and all have an average life, w, can be written from expression (3) as

$$CRCD_t = \frac{1}{w} \sum_{k=t-1}^{t} (t+1-k) I_k P_{kt} \qquad (6)$$

where $CRCD_t$ = cumulative replacement cost depreciation, year t
w = average life
I_k = gross investment, year t
P_{kt} = price index from date of acquisition to year t.

Note that average depreciation is assumed to be straight line, so the depreciation rate is 1/w.

Also, from expression (6) we can write current year gross replacement cost value of industry assets in year t as

$$RC_t = \sum_{k=t-1}^{t} I_k P_{kt} \qquad (7)$$

Thus the net replacement cost asset value can be calculated by subtracting expression (6) from expression (7). And this is the technique we employ. The first year of the analysis is 1972, requiring data on gross investment going back w years. And if w were, say, twenty years, we would need data on gross investment going back to 1953.

Annual gross investment at historical cost can be estimated from the following accounting expression

$$I_t = (NDA_t - NDA_{t-1}) + BD_t \qquad (8)$$

where I_t = gross investment, year t

NDA_t = net depreciable assets, year end t

BD_t = book depreciation, year t

However, the year 1965 was the first year that book depreciation statistics were published, although gross depreciable asset values were available before that year from the Department of National Revenue. Accordingly, estimation of gross investment for the years before 1965 entails estimation of book depreciation. In turn, this requires assumptions about asset lives. The following average asset lives were adopted based on the relationship between gross assets and book depreciation for the years in which data were available: oil and gas wells and manufacturing, 20 years; mining, 22 years; and utilities, 23 years.

D.2.2. Depletion Adjustments

Depletion expense is the proportion of cost of a firm's non renewable resources treated as used in a given year. Conceptually, the adjustment has much in common with that for depreciation. However, data discontinuities can preclude straightforward application of the depreciation type analysis.

For example, no separate records exist on gross depletable assets and only after 1964 were statistics kept on net depletable assets and book depletion. Thus derivation of depletable asset 'lives' using the same techniques as we used for depreciable assets was in the main not possible.

Even though the data were somewhat skimpy, we treated replacement cost depletion in a manner similar to depreciation. Thus, we had to generate a series for gross investment in depletable assets. Because of data gaps we had to make some rather heroic assumptions to derive the required net depletable asset and book depreciation streams pre 1965.

For the oil and gas wells, mining and utility sectors our presumption was that net depletable assets grew at the same rate as net depreciable assets. Book depletion in these sectors was derived using a ratio of 1:20 to net depletable assets in each year, the average relationship between 1965 and 1970 in the oil and gas wells sector. For manufacturing, the structure of the data allowed a somewhat more elaborate procedure to be used. Here we were able to derive a gross depreciable asset stream and therefore to apply directly the procedure used to adjust depreciable assets.[2]

We caution that the early data for the depletion adjustment in all sectors are suspect. However, the impact of these data on our results diminishes the further back the series goes. As well, in the utilities and total manufacturing sectors net depletable assets and book depletion are small components of the asset base. For example, net depletable assets, 1972 to 1980, averaged only 1.2 and 6 percent of net depreciable assets, respectively, in these sectors. For mining the average percentage was a more substantial but still relatively minor 40 percent. But for oil and gas wells net depletable assets were more than double the size of net depreciable assets over this period.

D.2.3. Land Adjustment

Land usually enters the asset base in a rate of return calculation at its book (acquisition) cost. Ideally, and especially when inflation is prevalent, its market value should be used. Unfortunately, such data are not available. We estimated market values for land in each sector in the following manner.

First we assumed that the book value of land carried in 1953 was equivalent to market value. Thereafter, yearly increments to this value were calculated. In the absence of a land value cost index we inflated the initial land value and all increments by the cost indexes used in the depreciation and depletion adjustments (see above). Summation of the inflated base value and increments yield an estimate of land market values in each year of concern (1972-1980).

D.2.4. Cost of Sales Adjustment Relating to Inventories

Inflation distorts measurement of the cost of inventories and hence of sales. For tax purposes, firms in Canada are required to employ FIFO inventory methods, which in effect means current selling prices are matched with costs reflecting earlier, lower prices. The tax rules prevent firms from applying replacement costs to current selling prices: Thus the LIFO method of inventory valuation is unacceptable.

Employment of FIFO understates the cost of sales, in the presence of inflation, and given the capital maintenance concept of income profits are overstated. Tarasofsky et al.[3] used the following inventory related cost of sales adjustment to compensate for inflation

$$CSADJ_t = \left(\frac{P_t - P_{t-1}}{P_{t-1}}\right) INV_{t-1}$$

where P_t = production cost index, year t

INV_{t-1} = opening inventories, current year.

This adjustment, by reducing the value of opening inventories, increases the cost attributed to a given level of sales.

Our inventory adjustment calculations were made as described above. The price indexes used were a manufacturing retail selling price index for that sector[4] and a coal and oil products price index[5] for the mining and oil and gas wells sectors. A suitable price index relating to the selling price of utility services could not be found, and therefore the GNE price index[6] was used for this sector.

D.2.5. Debt Adjustment[7]

In the absence of indexed debt, lenders lose and borrowers gain from unanticipated inflation. Under certain conditions, interest rates will rise to a level equivalent to the sum of the real rate of interest and the rate of inflation. This 'inflation premium' is an additional cash transfer from borrower to lender to compensate the lender for the erosion in the value of his original capital. For the borrower, the nominal interest charge is recorded as a tax deductible operating expense; for the lender, it is taxed as income. Consequently, the profit of the borrower is understated since what is effectively a repayment of debt is treated as a deduction from income. The lender's profit is overstated because what is a capital repayment is treated as income.

To offset the inflation premium embedded in current interest rates, the inflation adjustment adopted with respect to net longer term debt was related to average debt outstanding and the general level of prices, thus

$$GL_t = \frac{(NCL_t + NCL_{t-1})}{2} \; \frac{(GNE_t - GNE_{t-1})}{GNE_{t-1}}$$

where GL_t = net longer term debt inflation adjustment, year t
NCL_t = net longer term liabilities at end of year t
GNE_t = GNE deflator for year t.

As long as inflation prevails, this adjustment will serve to increase accounting profits.

A corresponding adjustment for short term debt is part of the treatment of working capital (described below).

D.2.6. Working Capital Adjustment

The problem of recording values at historical levels applies to all assets and liabilities when inflation contracts real values. In terms of working capital, and assuming the flows of current assets and liabilities are uniform throughout the year, the inflation adjustment is

$$WCA_t = \left[\frac{(CL_t + CL_{t-1})}{2} - \frac{(CA_t + CA_{t-1})}{2} \right] \frac{GNE_t - GNE_{t-1}}{GNE_{t-1}}$$

where WCA_t = working capital inflation adjustment, year t
CL_t = current liabilities, year end t
CA_t = current assets other than inventories, year end t
GNE_t = GNE deflator, year t.

The form of the adjustment takes the negative of working capital (current assets less current liabilities) at the midpoint and multiplies it by the rate of inflation. Consequently, when working capital is positive the adjustment reduces profits, a reflection of the loss in real values inflation imposes during the year.

D.2.7. Adjustments for Investments In and Loans to Other Companies

The problem of how to treat inter-company investments and loans is one of aggregation, not inflation. For simplicity and given the lack of suitable disaggregated information, we assume all such investments and loans are made to companies in the same industry.

A company buying shares in another company in the same industry will switch cash to shares. If the shares purchased were already issued, nothing would happen to the balance sheet of the company which originally floated them. The assets employed by that company remain the same. All that has happened is a change in ownership. In fact, in terms of the industry as a whole, some of its shares effectively have been retired. If the shares acquired were a new issue, assets will have been transferred between companies and the net assets employed in the industry would remain unchanged. Accordingly, in either instance - acquisition of existing shares or new subscriptions - inter-company share investments should be excluded from aggregate industry capital employed.

An adjustment is also required for profits. This is because any dividends received by the company acquiring the shares would enter its reported profit. However, this income would already be recorded as profit in the books of the company paying the dividend, since dividends are treated as a charge on retained earnings. Hence, to avoid double counting such dividends should be subtracted from aggregated profits.

Analogous considerations arise with respect to inter-company loans, assuming again they are all made to companies within the same industry. Their value should be deducted from the assets of the companies making them. However, no adjustment is required for interest on these loans since, unlike dividends, they do enter the profit statement of the company paying the interest. Accordingly, when aggregating over an industry group these transactions will cancel out, assuming, as we have, the loans are only made to companies in the same industry group.

D.2.8. Adjustments for Other Non-Current Assets

Other non-current assets include deferred charges and a variety of intangible assets such as goodwill, trademarks, franchises and the like, none of which are written off. Ostensibly an inflation adjustment would seem appropriate. But many such items are carried at a purely nominal value. Given a lack of knowledge about conferring realistic values, and since these items represent a negligible porportion of assets, they were excluded from the analysis. Their exclusion will impart a slight upward bias to computed rates of return.[8]

D.3 Calculation of Rates of Return

We calculate rates of return according to two definitions of capital employed - aggregate capital (AK) and equity capital (EK) - in both nominal and real terms.

Nominal aggregate capital employed (NAK) is

NAK = current assets (including inventories) less current liabilities plus depreciated values of fixed assets at book cost.

Real aggregate capital employed (RAK) is

RAK = current assets (including inventories) less current liabilities plus depreciated values of fixed assets at replacement cost.

Equity is treated as total capital employed less net longer term liabilities. This definition of equity does not distinguish between the various classes of shareholders and thus ignores real transfers that may take place between different shareholders when inflation is prevalent. However, when compared with the rate of return on overall capital it remains an indicator of transfers between creditors and shareholders.

Specifically, nominal equity capital (NEK) employed is simply the book value of total assets less short and long term debt, that is, NEK = net current assets (including inventories) less net longer term liabilities plus depreciated values of fixed assets at book cost.

Real equity capital (REK) is replacement value of total assets less long and short term debt, that is,

REK = net current assets (including inventories) less net longer term liabilities plus depreciated values of fixed assets at replacement cost.

D.3.1. Nominal After Tax Rate of Return on Aggregate Capital Employed

For any individual industry the nominal after tax rate of return on capital employed at time t is

$$NRC_t = \frac{RP_t + IN_t - DV_t - IT_t}{INV_t + WC_t + BK_t + BL_t}$$

where

RP_t = reported net profit before income taxes, year t
IN_t = net interest expense on longer term liabilities, year t
DV_t = dividends earned, year t
IT_t = income taxes paid, year t
INV_t = inventories valued at FIFO, mid year t
WC_t = working capital, mid year t
BK_t = depreciable and depletable assets at depreciated book value, mid year t
BL_t = land at book value, mid year t

Note that adjustments relating to industry aggregation are relevant to the calculation of nominal returns. That is why dividends (DV_t) are deducted from income in the numerator, while the net assets in the denominator exclude investments in other companies. The adding back of net interest paid relating to longer term liabilities ensures the income relates to aggregate capital employed, without deduction of payments for debt financing. Thus the way company assets are financed only affects taxes paid.

D.3.2. Real After Tax Rate of Return on Aggregate Capital Employed

In the light of the preceding discussion of inflation adjustments, the real rate of return on aggregate capital employed is defined as follows.

$$RRC_t = \frac{RP_t - DV_t + BD_t - RD_t + IN_t - CSADJ_t \pm WCA_t - IT_t}{INV_t + WC_t + RK_t + RL_t}$$

where

BD_t = book depreciation and depletion expense, year t

RD_t = replacement cost depreciation and depletion expense, year t

$CSADJ_t$ = cost-of-sales adjustment, year t (also known as inventory valuation adjustment)

WCA_t = real gain or loss on working capital, year t

RK_t = depreciable and depletable assets at depreciated replacement cost, mid year t

RL_t = land at replacement cost, mid year t

and the other variables are as defined beforehand.

Dividends (DV) are eliminated to avoid double counting on aggregation; book depreciation (BD) is added back to allow its substitution by replacement cost depreciation (RD). Net longer term interest expense (IN) is added back, since it is part of the aggregate return on capital. The inventory adjustment (CSADJ) effectively converts the cost of inventory to a LIFO basis. The adjustment for working capital (WCA) decreases attributed income when working capital is positive, and vice versa. The adjustment in the denominator replaces net book values of depreciable and depletable assets by net replacement cost values and converts land acquisition costs to market values.

The income tax charges (IT) relate to all taxes paid; no adjustment is made for taxes paid on income relating to assets which do not appear in the denominator. Such taxes would apply primarily to dividends received and interest on longer term liabilities. To this extent, the after tax rate of return is understated.

D.3.3. Nominal After Tax Rate of Return on Equity Capital Employed

The nominal (after tax) rate of return on equity at time t is defined as

$$NRE_t = \frac{RP_t - DV_t - IT_t}{INV_t + WC_t + BK_t + BL_t - NCL_t}$$

where RP_t = reported net profit before income taxes, year t

DV_t = dividends earned, year t

IT_t = income taxes paid, year t

INV_t = inventories valued at FIFO, mid year t

WC_t = working capital, mid year t

BK_t = depreciable and depletable assets at depreciated book value, mid year t

BL_t = land at book value, mid year t

NCL_t = net longer term liabilities, mid year t.

D.3.4. Real After Tax Rates of Return on Equity Capital Employed

The real rate of return on equity capital employed after tax is defined as

$$RRE_t = \frac{RP_t - DV_t + BD_t - RD_t - CSADJ_t \pm WCA_t + GL_t - IT_t}{INV_t + WC_t + RK_t + RL_t - NCL_t}$$

where

BD_t = book depreciation and depletion expense, year t

RD_t = replacement cost depreciation and depletion expense, year t

$CSADJ_t$ = cost-of-sales adjustment, year t (also known as inventory valuation adjustment)

WC_t = real gain or loss on working capital, year t

GL_t = gain on net longer term liabilities, year t

RK_t = depreciable and depletable assets at depreciated replacement cost, mid year t

RL_t = land at replacement cost, mid year t

and the other variables are as defined beforehand.

D.4 Data

Two sources had to be used for the accounting data used in the rate of return calculations because neither publication was available over the entire period required. The sources were

Pre 1965 - Department of National Revenue, Taxation Statistics
1965-1980 - Statistics Canada, Corporation Financial Statistics, (Catalogue No. 61-207).

The depreciation, depletion and land adjustments within each sector used the same price indexes. These were total capital expenditures on plant and equipment price indexes from Statistics Canada, Fixed Capital Flows and Stocks (Catalogue No. 13-211). The indexes used were

Oil and Gas Wells, and Mining - a mines, quarries and oil wells cost index
Utilities - an electric power and gas distribution cost index
Manufacturing - a total manufacturing cost index.

As discussed in Chapter 2, CERI Study #20, another cost index was used as well for the depreciation and depletion adjustment in the oil and gas wells sector. This was an unpublished index for capital costs in the oil and gas production sector prepared by the Canadian Petroleum Association (CPA) for the years after 1971.

The price indexes used in the inventory adjustments came from the following sources

Mining, and oil and gas wells - a coal and oil products price index from Statistics Canada, Statistical Review (Catalogue No. 11-003)
Utilities - GNE price index from Statistics Canada, Statistical Review (Catalogue No. 11-003)
Manufacturing - manufacturing retail selling price index from the Economic Council of Canada.

The GNE index from the source listed above was also used for the working capital and debt adjustments in each sector.

Footnotes

[1] The discussion is partly predicated on that in Tarasofsky, et al.(1981).

[2] We assumed the same life for depletable assets as was used for depreciable assets in each sector.

[3] See Tarasofsky et al. (1981) p.9.

[4] Source: Economic Council of Canada.

[5] Source: Statistics Canada Catalogue No. 11-003.

[6] Source: Statistics Canada, ibid.

[7] See Tarasofsky et al. (1981), p.10.

[8] This is the same procedure as employed by Tarasofsky et al. (1981), pp.10-11.

APPENDIX E

ESTIMATION OF BETAS AND THE COST OF EQUITY CAPITAL, OIL AND GAS PRODUCTION SECTOR

Appendix E

ESTIMATION OF BETAS AND THE COST OF EQUITY CAPITAL, OIL AND GAS PRODUCTION SECTOR

This appendix, which was mainly authored by Dr. Michael Brennan of the University of British Columbia, provides details on the Capital Asset Pricing Model (CAPM) used in Chapter 3 of CERI Study #20 to estimate security risk and the cost of equity capital.

According to the CAPM, the cost of equity capital for a firm or particular group of firms is equal to the yield on risk free debt instruments plus a risk premium which depends on the overall market risk premium and the relative systematic risk or Beta of the firm or group of firms.

In the following sections we clarify the relation between the cost of equity and the CAPM and show that the cost of equity depends on both the business risk of the company (the asset Beta) and the financial risk of the company (leverage).

E.1 The Cost of Equity Capital and the CAPM

The cost of equity capital for a company is defined as the expected rate of return that an investor could earn by investing in the shares of other companies of equivalent risk - it is the investor's opportunity cost of capital. If a company makes equity financed investments whose expected returns fall short of the cost of equity capital, investors will find they can obtain better returns elsewhere and will attempt to sell their shares. In doing so they will drive down the share price until at its new lower level the shares once again offer an expected rate of return commensurate with their risk. Thus the cost of equity capital is the minimum rate of return a company must demand on its equity financed investment if it is to avoid driving down its share price, assuming of course that any new investment has the same risk characteristics as the firm's current activities.[1]

The Capital Asset Pricing Model (CAPM) describes the equilibrium relationship between the expected rate of return investors require on a security and its risk. Thus by estimating the risk of an equity security, the expected rate of return required by investors may be inferred and this will constitute the cost of equity capital for the company issuing that security.

The fundamental concept underlying the CAPM is the distinction between diversifiable or insurable risk and non-diversifiable risk. For the investor, company specific risks may be effectively eliminated through the law of large numbers by holding a portfolio of many securities in which individual or specific risk will tend to cancel out. An example of a specific, diversifiable risk is the risk that a particular oil well will be dry. Since an investor's portfolio may contain many such prospects, some of which will be successful and some not, the risk of an individual well may be of little import to him in the same way that any individual claim is of little import to a life insurance company. Such risks are said to be diversifiable and consequently command little or no risk premium in the capital market.

An example of a non-diversifiable risk on the other hand would be the world price of oil, for a change in this price is likely to affect the value of many of the assets held by an investor. Obviously investors care more about non-diversifiable or systematic risk than they do about diversifiable risk and it is not surprising to find that investors are willing to accept such non-diversifiable risk only if by doing so they can expect to earn on average a higher return than is available on riskless debt securities - this higher average or expected return is the risk premium.

The average investor by definition holds a portfolio which is a pro rata share of the market portfolio of all common stocks as approximated for example by the Toronto Stock Exchange (TSE) Composite Index. Consequently, the risks which are non-diversifiable for him are those which contribute to the risk of the TSE Composite.

The contribution of a security to the risk of the market portfolio is measured by its Beta coefficient (B). The Beta is simply the slope of the regression line relating the return on the security to the return on the market index. A security which tends to go up (or down) in price by two percentage points when the TSE Composite advances (declines) by one percentage point would have a Beta of (2/1) = 2.0. Such a security is relatively undesirable to an investor holding a well diversified portfolio like the TSE Composite for it accentuates the positive or negative changes in the value of his portfolio - his risk. Therefore, a higher risk premium would be demanded for such a security. A security with a Beta of unity will tend to move pari passu with the TSE Composite, and will command a risk premium equal to that on the Composite Market portfolio. Finally, a security with a Beta of zero will tend to move completely independently of the Composite. If held in small quantities such a security will have a negligible effect on the risk of the investor's portfolio: its risk is entirely diversifiable and consequently it commands no risk premium.

In formal terms, the CAPM relationship is written:

$$\underbrace{E(R_j) - R_F}_{\substack{\text{Risk Premium}\\ \text{on Security}}} = \underbrace{B_j}_{\substack{\text{Beta of}\\ \text{Security}}} \times \underbrace{(E(R_M) - R_F)}_{\substack{\text{Market Risk}\\ \text{Premium}}} \tag{9}$$

where $E(R_j)$ = expected rate of return on security j
R_F = riskless interest rate
$E(R_M)$ = expected rate of return on the market portfolio as represented for example by the TSE Composite Index
B_j = Beta of security j.

The CAPM is a popular technique for estimating the cost of capital and has intuitive appeal. But it does raise certain statistical and theoretical issues which remain outstanding. The statistical problems focus on conducting thorough tests to ascertain the validity of the model; the theoretical concerns include whether Beta alone is sufficient to characterize systematic risk.[2]

E.2 Business and Financial Risk

To see the relation between the risk of a company's equity, the risk of the company's assets and its leverage consider the simplified situation depicted in Figure E.1 (which ignores corporate taxes).

It follows from the identity of assets and liabilities that

$$A \times R_A = D \times R_D + E \times R_E \tag{10}$$

or, writing $A = V = D + E$

$$R_A = \frac{D}{V} R_D + \frac{E}{V} R_E \tag{11}$$

where A = total assets (market value)

R_A = return on total assets

D = total debt and preferred stock at market value

R_D = return on debt

E = total equity (market value)

R_E = return on equity

V = total market value of firm.

Figure E.1: Simplified Balance Sheet

Assets; R_A	Debt : D; R_D Equity : E; R_E
A	$V = D + E$

Equation (11) implies that the Beta of the firm's assets - the business risk - is equal to a weighted average of the Betas of the firm's debt and equity:

$$B_A = \frac{D}{V} B_D + \frac{E}{V} B_E \tag{12}$$

where B_A, B_D and B_E are the Betas of the assets, debt and equity respectively.

If the firm's debt were riskless then $B_D=0$ and (12) implies

$$B_E = \frac{V}{E} B_A = (1+D/E)B_A \tag{13}$$

Equation (13), then, illustrates that the Beta of the equity depends both on the Beta of the assets, B_A, and the firm's leverage as represented by the ratio of debt to equity D/E. The higher the ratio of debt to equity, the higher the equity Beta.

Therefore, in analyzing changes in the Betas of a firm's equity securities over time it is important to remember that these may be due to both changes in the underlying business risk, B_A, and to changes in the leverage D/E.

One remaining complication derives from the possibility that the tax deductibility of corporate interest payments provides a systematic benefit for firms which issue debt securities. Opinion on this is divided at present - there are strong arguments on both sides.

At one extreme, if there were no net tax benefits to be passed on to shareholders from the tax deductibility of interest payments, then equation (12) correctly describes the relation between asset Betas and debt and equity Betas. At the other extreme, if the full tax benefits are passed on to shareholders (12) must be replaced by

$$B_A = \frac{D}{V-tD^*} B_D + \frac{E}{V-tD^*} B_E \tag{14}$$

where t is the corporate tax rate and D is the market value of the firm's debt and preferred obligations and D* is just the value of the outstanding debt (i.e., excluding preferred stock).

When we present estimates of asset Betas in Section E.7, we shall do so under five different assumptions.

i) no tax benefit of debt ($t=0$); riskless debt ($B_D=0$)
ii) full tax benefit of debt ($t=0.46$); riskless debt ($B_D=0$)
iii) no tax benefit of debt ($t=0$); risky debt and preferred securities ($B_D=0.2$)[3]

iv) full tax benefit of debt (t=0.46); risky debt and preferred securities (B_D=0.2)

v) an intermediate case (t = 0.23)

In the following section we consider the estimation of equity Betas.

E.3 Equity Beta Estimation

Assuming a stable relationship between individual security returns and market returns, the Beta of security j in principle can be estimated from the time series regression of security returns on market returns:

$$R_{jt} = a_j + b_j R_{mt} + e_{jt} \qquad t=1 \dots T \qquad (15)$$

where $R_{jt} = \frac{P_{jt} + D_{jt} - P_{jt-1}}{P_{jt-1}}$ is the rate of return on security j in period t

P_{jt} is the price of the security at the end of period t

D_{jt} is the dividend paid during the period

R_{mt} is the rate of return on the 'market portfolio' as represented, for example, by the TSE 300 index

e_{jt} is a random error term

a_j and b_j are parameters, with b_j being the Beta coefficient.

In practice it makes little difference whether dividends are included in calculating the rates of return, and for reasons of economy they are often neglected.

Strictly speaking, equation (10) holds only if the length of each period is infinitesimal; if non-infinitesimal periods are used the relation between R_j and R_m will be non-linear, given the compounding of returns. For this reason it is desirable from a theoretical viewpoint to estimate the logarithmic or continuously compounded version of (10):

$$r_{jt} = a_j + b_j r_{mt} + e_{jt} \qquad t=1 \dots, T \qquad (16)$$

where $r_{jt} = \log(1+R_{jt})$
$r_{mt} = \log(1+R_{mt})$

We devote our attention to equation (16).

The traditional way of estimating Betas has been to estimate equation (15) or (16) using 60 monthly rates of return. There are two potential problems with this, arising from possible non-stationarity in the relation and from the phenomenon of thin trading. First we suggest how the thin trading problem can be overcome and then suggest that the problem of non-stationarity can be ameliorated by using shorter periods to calculate returns. Unfortunately, this exacerbates the thin trading problem.

Suppose that we have 60 monthly rates of return on the security whose beta we wish to estimate and on the market index. In principle we could use these data to estimate beta directly from relation (16). In practice a problem arises because some securities do not trade every day. If the security does not trade on the first and last day of the month it is impossible to calculate the true rate of return over the month; a similar problem arises in calculating the return on the market index if the constituent securities do not trade every day.

In practice this problem is ignored by treating the closing price for each month as though it were the price realized at the close on the last day of the month. In fact, if the security trades thinly or infrequently this closing price may have been realized several days prior to the end of the month. Therefore the general use of closing price returns does give rise to a possible misalignment of returns - what is recorded as the December return may actually be the return from November 16 to December 18. This misalignment of returns causes systematic biases in the Beta coefficient estimated from relation (16); several procedures have been suggested to deal with it.

Fowler et al.[4] report the results of extensive simulations of alternative Beta estimators in the presence of thin trading when monthly returns are used. On the basis of these simulations it appears that the most reliable estimator in terms of bias and mean square error is that of Scholes-Williams.[5]

The Scholes-Williams estimator is obtained by regressing security returns on lagged, concurrent and leading market returns:

$$\left.\begin{aligned} R_{jt} &= a_j^{-1} + b_j^{-1} R_{mt-1} + e_{jt} \\ R_{jt} &= a_j^{0} + b_j^{0} R_{mt} + e_{jt} \\ R_{jt} &= a_j^{+1} + b_j^{+1} R_{mt+1} + e_{jt} \end{aligned}\right\} \tag{17}$$

and the Scholes-Williams estimate b^{sw} is:

$$b_j^{sw} = \frac{b_j^{-1} + b_j^{0} + b_j^{+1}}{1 + 2\rho_m} \tag{18}$$

where ρ_m is the serial correlation of the market returns:

$$\rho m = \sum_{t=2}^{T} (r_{mt} - \bar{r}_m)(r_{mt-1} - \bar{r}_m) / \sigma^2(r_m)$$

$\bar{r}_m$ is the average market return and $\sigma^2(r_m)$ is the variance of the market return.

Use of relations (17) and (18) leads to consistent estimates of Beta provided that the security trades each month and relations (15) and (16) are stable over the five year (60 month) estimation period.

We are interested in whether the risk of oil and gas firms may have changed over the period 1972-1982. Use of monthly return data would involve calculating Betas over the periods 1968-1972 and 1978-1982 during which there is a high probability the Betas will have changed. For this reason it is desirable to estimate the Betas over shorter periods of time using more frequent observations: 52 weekly observations is the natural candidate.

While use of weekly return data can lead to more precise timing of the Beta estimates, it increases the potential problem of misalignment of returns due to thin trading. Unfortunately we have no simulation results for weekly data to guide us in the choice of a Beta estimation technique. However, the Scholes-Williams procedure is known to provide consistent estimates of Beta if securities trade every week. Therefore the Scholes-Williams procedure was employed, omitting weeks in which no trade in a security was registered.

E.4 Data

The focus of the analysis is on the Canadian oil and gas producing sector. A Toronto Stock Exchange industry index is maintained for this subsector and is included in the discussion below. However, the company mix in this index has changed in the decade; a more thorough examination can be undertaken starting with individual company Betas and balance sheets. The market return used for all the Beta calculations is derived from the TSE 300 Composite index.[6]

The data were drawn from several sources. An initial list of 40 producing Canadian oil and gas companies was selected as the appropriate data set. The list was compiled by excluding integrated companies and those with significant operations beyond the petroleum production sector. Also, it was necessary of course that the company be traded on the TSE both in 1972 and 1982.

Weekly stock price data for both 1972 and 1982 were taken manually from The Globe and Mail Business Section. Prices were collected for 36 companies in 1972 and for 33 companies in 1982 (consistent data were not available for all 40 companies). The Toronto Stock Exchange Composite index (TSE 300) was drawn from the same source. While the data for 1972 were fairly thorough, the 1982 data presented frequent gaps both from weeks where the stock did not trade and from trading suspensions.

This necessitated reducing the list to 31 companies for which data were available both in 1972 and 1982 in order that the comparison of aggregated Betas be based on the same portfolio of stocks. Equity Betas were calculated on these 31 companies - concurrent, lagged and leading and the Scholes-Williams average Betas were derived.

The calculation of asset Betas (see above) requires information on company financial structure. Adequate financial data were only readily available for 17 companies, for both 1972 and 1982. Long term debt, preferred stock totals, number of common shares outstanding and average stock price were derived from a database of corporate financial summaries for the 1971 and 1981 year ends. Table E.1 presents a list of the 31 companies examined; companies for whom complete financial data were available are noted.

This information enabled the calculation of asset Betas, pre-tax and adjusted for tax for each company. The industry averages were computed by appropriate weights. Specifically, the industry or portfolio equity Beta was calculated using weights of the company total equity relative to the total industry equity. The pre-tax asset Betas were derived using relative company assets as weights.

Inter-industry comparisons of Betas were undertaken using Toronto Stock Exchange industry indices obtained directly from the Toronto Stock Exchange both for 1972 and 1982. The indices were metals and minerals, oil and gas (including integrated oils), industrial manufactured products, and utilities. Within the oil and gas sector two subindices were available: integrated oils and oil and gas producers. Again the concurrent, lagged and lead Betas were calculated to derive the Scholes-Williams estimator.

E.5 Equity Beta Estimates

The concurrent Betas used in the Scholes-Williams estimates generally had t values significantly different from zero.[7] The leading and lagged Betas were not generally significant.

The first three lines of Table E.2 report estimated equity Betas (in the Scholes-Williams form) for the selected sample of companies in the oil and gas production sector (OGPSS) for 1972 and 1982 on three different bases.[8]

TABLE E.1
COMPANIES EXAMINED FOR THE BETA ANALYSIS

1. American Leduc
2. Asamera*
3. Bow Valley*
4. Calvert
5. Canadian Northwest Energy
6. Canadian Southern
7. Canadian Reserve*
8. Charter Oil and Gas
9. Chieftain*
10. Dome*
11. Merland*
12. MidCon
13. N. Canadian Oils*
14. Northland
15. Numac*
16. Oakwood*
17. Page*
18. Petrol
19. Place
20. Ponder
21. Ram
22. Ranger*
23. Scurry Rainbow*
24. Sogepet
25. Spooner
26. Total*
27. Trans Canada Resources*
28. Ulster*
29. United Canso*
30. United Reef
31. Westburne*

* For these 17 companies, financial data were available.

TABLE E.2
INDUSTRY EQUITY BETA ESTIMATES

		1972	1982
Oil and Gas Production Sector	- unweighted, 31 companies	1.37	1.50
	- unweighted, 17 companies	1.36	1.38
	- equity weighted, 17 companies	1.32	1.26
	- weighted excluding Dome Petroleum, 16 companies	1.40	1.48
TSE Industry Indices:			
Oil and Gas		1.03	1.09
Integrated Oils		0.88	0.89
Oil and Gas Producers		1.22	1.21
Metals and Minerals		1.07	1.18
Utilities		0.57	0.50
Industrial Products		1.14	0.91

The unweighted average Beta (of the 17 company sample, in Scholes-Williams form) which gives all companies the same weight increases slightly between 1972 and 1982 from 1.36 to 1.38. The weighted average Beta weights each company's Beta by the market value of its equity, and therefore is more representative of the larger firms in the industry. This Beta value falls from 1.32 in 1972 to 1.26 in 1982. Dome Petroleum accounted for about 64 percent of the equity value weights in the OGPSS[9] in 1982. Given the extraordinary circumstances surrounding this company, little significance can be attached to its Beta estimate, affected as it was by threatened bankruptcy, implicit government guarantees, and the like. If this company were removed from the sample the weighted average industry Beta increases from 1.40 in 1972 to 1.48 in 1982 as shown in the fourth line of Table E.2. On a weighted basis there was a slight decrease in the equity Betas of the OGPSS between 1972 and 1982. However both on an unweighted basis and on a weighted basis excluding Dome there was an increase in the equity Betas.

The OGPSS Beta estimates all exceed those of the other indices shown in Table E.2 by a wide margin, including the general Oil and Gas Index. The Beta of the average firm in OGPSS is roughly 30 percent higher than that of the average firm in the TSE Oil and Gas Index. However, it should be noted that the Oil and Gas Index in 1982 will be affected to a large extent by Dome Petroleum and even more importantly also includes integrated companies typically having Betas less than unity (See Table E.2).

The equity weighted Beta of the sample exceeds the TSE oil and gas producers index by some 8 percent in 1972 and by some 4 percent in 1982. The OGPSS company mix is held constant for the two sample years and differs from the TSE oil and gas producers company mix which may vary between 1972 and 1982. The OGPSS appears to be a slightly riskier than average subset of the TSE producer index.

The Beta of the TSE Oil and Gas Index shows only a marginal change, 1982 over 1972, and indeed is not much 'riskier' than the TSE Composite. The mining index Beta has shown some increase in 1982 compared with 1972, while manufacturing Betas have decreased and are below the TSE Composite index. As would be expected the Beta for the utilities is low - about half that for the composite - given the stability regulation confers on returns.

In summary, the equity Beta of the average firm in the OGPSS exceeds that of the average TSE 'composite' company by a wide margin, and has increased somewhat from 1972 to 1982 on both an unweighted basis and on an equity weighted basis (excluding Dome).

E.6 Cost of Equity Capital

From Section E.1, the expression for the risk premium on a security given by the CAPM (see equation (9)) is

$$E(R_j) - R_F = B_j(E(R_M) - R_F)$$

Since the equilibrium expected rate of return on a security $E(R_j)$ is simply the cost of equity capital for that company, this equation implies

$$\text{Cost of Equity} = R_F + B_j(E(R_M) - R_F)$$

In other words, the cost of equity capital comprises the riskless interest rate plus Beta x the market risk premium.

Table E.3 contains estimates of the cost of equity for the OGPSS in 1972 and 1982. Estimates of the nominal cost of equity refer to the respective months of December, on account of the disturbed conditions prevailing in Canadian capital markets in the earlier months of 1982. A more normal situation prevailed in December, making the historical comparisons more reasonable.[10]

Estimates are provided in both real and nominal terms. The following data definitions are used, with the Beta estimates reported in the previous section.

(1) Riskless interest rate (nominal): yield on 90-day Treasury Bills from the Bank of Canada Review, end year.
Riskless interest rate (real): 0.4 percent. This is the average real return earned on Treasury Bills in Canada over the period 1926-1980 as reported by Carlton, Ezra and Sharp.[11]

(2) The market risk premium. We take the market risk premium to be in the range of 8.0 - 9.4 percent, predicated on the following. Carlton, Ezra and Sharp report the average risk premium on Canadian stocks over the period 1926-1980 as 9.38 percent. This compares with a value of 8.8 percent quoted by Ibbotson and Sinquefield[12] for the United States over the period 1926-1977. Brennan and Schwartz[13] report a market risk premium of 7.9 percent for Canadian stocks over the shorter time interval 1968-1980.

Given these parameters our best estimates of the cost of equity capital for the OGPSS is taken as the mid-point of the range and shown in the last column of Table E.3.

The weighted results for 1982 exclude Dome Petroleum. In nominal terms the cost of equity capital appears to have increased by some 6 percentage points or not far short of one-half of its earlier value. However, most of this is accounted for by higher inflation and, assuming that the average real return on Treasury bills will continue to be of the order of one-half percent per year, the real increase in the cost of equity 1982 over 1972 is of the order of one percentage point (weighted) and just a marginal increase unweighted. But if the real returns on Treasury bills were to be sustained over the long run at

TABLE E.3

COST OF EQUITY CAPITAL ESTIMATES FOR OIL AND GAS PRODUCER SECTOR COMPANIES 1972 AND 1982

A. Nominal Cost of Equity

	Nominal Interest Rate +	Market Risk Premium	x Beta =	Cost of Equity Range	Cost of Equity Mid-Point
1972	3.9 %	8.0 - 9.4 %	1.36 U	14.8 - 16.7%	15.7%
			1.32 W	14.5 - 16.3%	15.4%
			1.40 Wed	15.1 - 17.1%	
1982	9.3 %	8.0 - 9.4 %	1.38 U	20.3 - 22.3%	21.3%
			1.26 W	19.4 - 21.1%	
			1.48 Wed	21.1 - 23.2%	22.2%

B. Real Cost of Equity

	Real Interest Rate +	Market Risk Premium	x Beta =	Cost of Equity Range	Cost of Equity Mid-Point
1972	0.4 %	8.0 - 9.4 %	1.36 U	11.3 - 13.2%	12.2%
			1.32 W	11.0 - 12.8%	11.9%
			1.40 Wed	11.6 - 13.6%	
1982	0.4 %	8.0 - 9.4 %	1.38 U	11.4 - 13.4%	12.4%
			1.26 W	10.5 - 12.2%	
			1.48 Wed	12.2 - 14.3%	13.3%

U - unweighted, 17 companies

W - weighted, 17 companies

Wed - weighted excluding Dome

recent (end 1983) high levels of 4 percent, the current 1983 cost of equity capital could be considerably higher than that reported for 1982.

E.7 Asset Beta Estimates

Section E.1 of this appendix showed that the equity Beta of a company or industry depends upon both the asset Beta of the company or industry and upon its leverage or capital structure. There was a quite dramatic change in the leverage of our oil and gas production sector company sample between 1972 and 1982.

We define the common equity ratio as:

$$\text{Common Equity Ratio} = \frac{\text{Market Value of Common Shares}}{\text{Market Value of Common + Book Value of Preferred + Book Value of Long Term Debt}}$$

While it would have been preferable to have used market values for all securities, such values were readily available only for common stock. However, we do not believe that the use of book values for debt and preferred will cause a significant distortion in this context.

On this basis we find for our sample the following change in capital structure between January 1, 1972 and January 1, 1982.

		1972	1982
Common Equity Ratio:	17 company sample	82%	48%
	excluding Dome	82%	65%

It is clear that even apart from Dome there was a significant increase in reliance on fixed income financing by the OGPSS between the beginning of 1972 and the beginning of 1982, and this would have accounted, other things equal, for at least part of the increase in the equity Beta.

As explained in Section E.1, the relation between asset Betas, equity Betas and leverage depends upon the assumptions made about the debt Beta and the value of the corporate tax deduction to shareholders.

In Table E.4 we have computed asset Betas using relation (12) beforehand for the OGPSS assuming the maximum tax benefit and zero tax benefit, and assuming that the debt is riskless and then that it has a Beta of 0.20.

The riskless debt assumption is probably appropriate for 1972, given the modest industry reliance on debt financing. By 1982 the situation had clearly changed and the assumption of a Beta of 0.20 for the debt or an even higher level is more reasonable. The arrows in the table indicate the appropriate comparisons under the assumptions of zero and full tax benefit.

Since it is unclear precisely to what extent shareholders benefit from the tax deductibility of corporate interest (the bounds are 0 and 46 percent) we have shown as the most likely case a 23 percent tax benefit rate combined with an increase in the debt Beta from 0 in 1972 to 0.20 in 1982. This result and almost every other one suggests that the modest increase in the industry equity Betas discussed earlier between 1972 and 1982 has not been due to an increase in the underlying asset risk, but due primarily to the increase in leverage. Indeed, the evidence appears to be that there has been a modest decline in the average weighted asset Beta in the OGPSS between 1972 and 1982.[14]

TABLE E.4
ESTIMATED ASSET BETAS FOR OGPSS

	1972	1982*
Estimated Asset Betas (weighted) assuming:		
1. No Tax Benefit		
a) Riskless Debt and Preferred	1.08	0.85
b) Debt and Preferred with Beta - 0.20	1.12	0.94
2. Full Tax Benefit (46%)		
a) Riskless Debt and Preferred	1.16	1.03
b) Debt and Preferred with Beta - 0.20	1.20	1.13
3. Most likely (23% tax benefit, Debt Beta (1972) = 0, Debt Beta (1982) = 0.20)	1.12	1.02

* Excludes Dome Petroleum

FOOTNOTES

[1] As such, the cost of equity capital is related to the concept of 'hurdle' rates of return; see discussion in Chapter 3, Volume 1.

[2] For criticism of the CAPM, for example see Roll and Ross (1983).

[3] Reilly and Joehnk (1976) report an average Beta for United States industrial bonds of 0.16-0.20 for 1967-1972. Weinstein (1981) reports a value of 0.195 for 1970-1974. While bond Betas are not significantly related to bond ratings they are found to be an increasing function of maturity and a decreasing function of the coupon rate.

[4] David J. Fowler, C. Harvey Rorke and Vijay M. Jog (1980).

[5] M. Scholes and J. Williams (1977).

[6] For consistency with the company returns where dividend inclusion was impossible, the basic index was used in preference to the market return index.

[7] At a 95 percent level of confidence. Of the 17 companies in the final sample, 12 had Betas significantly greater than zero in 1972; 16 had significant Betas in 1982.

[8] Asset Betas are dealt with in Section E.6 below.

[9] Based on beginning of year stock prices.

[10] The estimates in real terms are not affected by capital market fluctuations in 1982 since the real riskless interest rate is based on long term averages, not on Treasury Bill rates recorded during the year.

[11] C. G. Carlton, D. D. Ezra and K. P. Sharp, "Canadian Investment Returns and Economic Statistics, 1962-1980", mimeo.

[12] R. G. Ibbotson and R. A. Sinquefield (1977).

[13] M. J. Brennan and E. S. Schwartz (1982).

[14] It should be noted that owing to its dominant size and abnormal situation in 1982, Dome was omitted from the 1982 calculations.

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